	OAH 3-2500-21343-2 MPUC E-017/GR-10-239

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS

FOR THE PUBLIC UTILITIES COMMISSION

In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Utility Service in Minnesota	**FINDINGS OF FACT, CONCLUSIONS AND RECOMMENDATION**

This matter came on for hearing before Administrative Law Judge Kathleen D. Sheehy on November 17-19, 2010, at the offices of the Minnesota Public Utilities Commission, 121 Seventh Place East, Suite 350, St. Paul, Minnesota. The OAH record closed on January 14, 2011.

Bruce Gerhardson, Associate General Counsel, Otter Tail Power Company, 215 South Cascade Street, P.O. Box 496, Fergus Falls, MN 56538-0496; and Richard J. Johnson, Michael J. Bradley, and Valerie M. Means, Attorneys at Law, Moss & Barnett, 90 South Seventh Street, 4800 Wells Fargo Center, Minneapolis, MN 55402, appeared for Otter Tail Power Company (Applicant, Otter Tail, or OTP).

Julia Anderson and Linda S. Jensen, Assistant Attorneys General, 445 Minnesota Street, Suite 1400, St. Paul, MN 55101, appeared for the Minnesota Department of Commerce, Office of Energy Security (OES).

Ronald M. Giteck, Assistant Attorney General, 445 Minnesota Street, Suite 900, St. Paul, MN 55101, appeared for the Minnesota Office of the Attorney General, Residential Utilities Division (OAG/RUD).

Andrew P. Moratzka, Attorney at Law, Mackall Crounse & Moore, PLC, 1400 AT&T Tower, 901 Marquette Avenue, Minneapolis, MN 55402-2859, appeared for Enbridge Energy, Limited Partnership, and Enbridge Energy Company, Inc. (Enbridge).

Richard J. Savelkoul, Attorney at Law, Felhaber Larson Fenlon & Vogt, PA, 445 Cedar Street, Suite 2100, St. Paul, MN 55101-2136, appeared for the Minnesota Chamber of Commerce (MCC or the Chamber).

Commission staff members Stuart Mitchell, Jerry Dasinger, and Michelle Rebholz attended the hearing.

STATEMENT OF THE ISSUES

1. Is the test year revenue increase sought by the Company reasonable, or will it result in unreasonable and excessive earnings?

2. Is the rate design proposed by the Company, including proposed revisions to customer charges, reasonable?

3. Are the Company's proposed capital structure, cost of capital, and return on equity reasonable?

4. Does the Minnesota Boundary Guidelines Study represent the most reasonable analysis of the classification of the Company's electric lines between transmission and distribution functions, and should it serve as a basis for cost allocation?

5. Has the Company fairly allocated costs between its North Dakota, South Dakota, Minnesota, and wholesale jurisdictions?

6. Is the Company's proposal to remove asset-based wholesale margins from base rates to the fuel clause adjustment reasonable and appropriate?

7. Is the Company's proposal to move cost recovery of transmission projects from its transmission cost recovery rider to base rates reasonable and appropriate?

Based on the evidence in the hearing record, the Administrative Law Judge makes the following:

FINDINGS OF FACT

1. Otter Tail Power is a Minnesota corporation with headquarters in Fergus Falls, Minnesota. Until July 1, 2009, OTP was an operating division of Otter Tail Corporation; OTP is now a separate legal entity and wholly-owned subsidiary of Otter Tail Corporation, a public utility holding company.

2. OTP provides service to 423 communities and rural areas in western Minnesota, northeastern South Dakota, and the eastern two-thirds of North Dakota. Its service territory is approximately 50,000 square miles. The average population of communities it serves is approximately 400; more than half of those communities have populations less than 200, and only three communities (Bemidji, Fergus Falls, and Jamestown, North Dakota) have populations exceeding 10,000. As of year-end 2009, OTP was providing electricity and energy services to 129,284 total customers: 60,598 in Minnesota, 56,944 in North Dakota, and 11,742 in South Dakota.[1]

[1] Ex. 14, Brause Direct at 3.

3. On April 2, 2010, Otter Tail Power filed this general rate case seeking to increase rates in the amount of $10,632,383, or approximately 8.01 percent. In its filing, OTP used a historical test year ending December 31, 2009, with adjustments for known and measurable changes. It also filed a proposed interim rate schedule seeking an interim rate increase of $5,051,076, or approximately 3.80 percent on an annualized basis.

4. On May 27, 2010, the Commission found OTP's application to be substantially complete as of April 2, 2010, and it extended the ten-month deadline for completing this case until April 25, 2011. The Commission also required OTP to submit a supplemental filing regarding travel, entertainment, and related employee expenses, consistent with Minn. Laws 2010, Ch. 328.[2] On the same date, the Commission issued orders authorizing OTP to collect its proposed interim rates and initiating a contested case proceeding.[3]

5. The following parties intervened in this matter: the Chamber, Enbridge Energy Limited Partnership (Enbridge), and the International Brotherhood of Electrical Workers (Local Union 949).[4] Missouri River Energy Services (MRES) filed a petition to intervene as a party, to which OTP objected. After briefing, the Administrative Law Judge denied the intervention petition of MRES.[5]

Public Hearings

6. Public hearings were held on September 7, 2010, at 1:00 p.m. at the Bemidji City Hall in Bemidji (no members of the public spoke); September 7, 2010, at 7:00 p.m. at the Youngquist Auditorium of the University of Minnesota in Crookston (no members of the public spoke); September 8, 2010, at 1:00 p.m., at the Fergus Falls City Council Chambers in Fergus Falls (no members of the public spoke); and September 8, 2010, 7:00 p.m., at the Morris City Hall in Morris (one member of the public spoke). The person who spoke in Morris voiced his support for the rate increase.

7. The Administrative Law Judge received two public comments. One commenter requested that OTP executives and employees reduce their compensation, and the other urged the Commission to provide rate relief to non-profit customers. In addition, the Commission received three public comments: one proposed to reduce the Company's tree trimming expense; one expressed concern about the Company's request for recovery of its Big Stone II expenses; and one discussed concerns about the demand rate.

8. In addition, Great River Energy (GRE) and MRES filed comments supporting the Company's use of the Minnesota Boundary Guidelines to define

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[2] *In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Utility Service in Minnesota*, E-017/GR-10-239, Order Accepting Filing, Suspending Rates, Extending Suspension Period, and Requiring Supplemental Filing (May 27, 2010).
[3] *Id*., Order Setting Interim Rates (May 27, 2010) and Notice and Order for Hearing (May 27, 2010).
[4] First Prehearing Order (June 30, 2010).
[5] Second Prehearing Order (Sept. 1, 2010).

transmission and distribution assets. GRE and MRES pointed out that the Boundary Guidelines were established by consensus after a lengthy generic proceeding, and they argued that the Guidelines should not be changed in this rate case because of the impact on other transmission owners with facilities located in OTP's pricing zone. Specifically, they pointed out that any reclassification of OTP's transmission facilities to the distribution function will have a "net negative financial outcome" for other transmission providers, because Midwest ISO applies the host transmission owner's classification of facilities in its pricing zone to all facilities within the zone, including those of other owners. GRE and MRES advocated that the Commission conclude that OTP has reasonably applied the Minnesota Boundary Guidelines and reject any proposal to functionalize transmission into "sub-transmission" or "up-stream/down-stream" categories. They contended that the guidelines continue to be appropriate and that no new criteria are necessary.[6]

I. BIG STONE II.

9. The Big Stone II project (Big Stone II) was a 500-580 megawatt base load coal generation project that OTP developed and pursued with six other regional utilities from 2005 until 2009. The project, which was to use supercritical or ultra-supercritical pulverized coal technology, was to share infrastructure and facilities with the existing Big Stone plant in Big Stone, South Dakota. The planned technology was to achieve higher efficiencies and lower carbon emissions than conventional coal plants.[7]

10. Plans for Big Stone II incorporated a number of features that would have benefited the original Big Stone plant as well, including new equipment to reduce emissions of SO2 and mercury.[8]

11. OTP and its partners began the process of obtaining all the major permits and approvals necessary for construction of the project, although the only approval required in Minnesota was the Certificate of Need for the transmission lines that would connect Big Stone II to the transmission grid.[9]

12. On September 18, 2007, the Big Stone II applicants filed a letter with the Commission stating that two of the original applicants—Great River Energy and Southern Minnesota Municipal Power Agency— were withdrawing from the project.

[6] GRE Comment (Oct. 26, 2010); MRES Comment (Nov. 5, 2010).
[7] *In the Matter of the Application of Otter Tail Power Company and Others for Certification of Transmission Facilities in Western Minnesota,* PUC Docket No. E-017, ET 6131, ET-6130, ET-6144, ET 6135, ET-10/CN-05-619, Order Granting Certificate of Need with Conditions at 7 (March 17, 2009) (*Big Stone II CON Order*).
[8] *Id.* at 8.
[9] Ex. 14, Brause Direct at 15.

13. The Commission issued the Certificate of Need (CON) for the Big Stone transmission lines on March 17, 2009. The Commission approved OTP's 2005 Integrated Resource Plan (OTP IRP), which included Big Stone II, on March 18, 2009.[10]

14. The March 17, 2009, CON did not directly address the Big Stone II generator, because that was to be built in South Dakota and did not require Minnesota approval. Nonetheless, in its Order granting the CON, the Commission found that the applicants had demonstrated that Big Stone II was justified "under any reasonably foreseeable circumstance" in which construction costs would "not exceed the $2600-$3000/kW range and carbon regulation costs do not exceed $26/ton."[11]

15. The Commission's Order put "Otter Tail on notice of the Commission's present intention to shield Otter Tail's ratepayers from bearing any construction costs exceeding the $2600-$3000/kW range and carbon regulation costs exceeding $26/ton" adjusted for time and inflation, attributable to the Big Stone II proposal.[12] The Commission noted, however, that the Order did "not preclude any party from advocating a contrary position" or "pre-judge whether Otter Tail's ratepayers should bear . . . costs up to these levels." The Order noted that such questions would more appropriately be addressed in a future rate proceeding.[13]

16. The Commission found that it was "able to determine that, under a broad range of reasonable scenarios and subject to reasonable conditions, the Big Stone II proposal is more cost-effective than other alternatives."[14] The Commission specifically found:

> [T]he Big Stone II proposal is at least as reasonable and prudent as any other alternative demonstrated by a preponderance of the evidence on the record. No party claims to have demonstrated a more reasonable and prudent alternative for meeting the forecasted demand, or denies that the applicants will need to acquire at least some new sources of electricity generated from non-renewable fuels.[15]

17. The Big Stone II project agreements required OTP to make a final decision by September 11, 2009, committing to continue its participation in the project through financing, construction, and operation of the plant.[16]

18. In September 2009, OTP withdrew from participation in Big Stone II.[17] OTP's stated reasons for the withdrawal included:

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[10] *In the Matter of Otter Tail Power Company's 2005 Integrated Resource Plan,* PUC Docket No. E-017/RP-05-968 (March 18, 2009) (*OTP IRP Order*).
[11] *Big Stone II CON Order* at 29.
[12] *Id.*
[13] *Id.*
[14] *Id.* at 32.
[15] *Id.*
[16] *Id.* at 28.
[17] Ex.14, Brause Direct at 26.

(a) significant unanticipated changes to long-term forecasts for on-peak and off-peak energy prices and changes in projected customer demand;
(b) fundamental shifts in the energy marketplace and resource additions in the Company's region;
(c) forecasts of energy prices in the 2012-2024 time frame that were 40-50 percent lower than previous forecasts;
(d) financial market conditions brought on by the economic downturn beginning in 2008, which made raising capital unreasonably risky and potentially more costly, and making it increasingly difficult to find debt financing at a reasonable cost, along with an increased cost of raising equity capital;
(e) unsuccessful attempts to find replacements for the two Big Stone II participants that withdrew in 2007, increasing OTP's ownership share from 19.33 percent to 26.54 percent;
(f) uncertainty about the regulatory climate;
(g) uncertainty about adequate and timely cost recovery; and
(h) uncertainty about protracted appellate processes.[18]

19. No party has disputed that it was reasonable for OTP to withdraw from the Big Stone II project.

20. In December 2009, OTP filed a petition to obtain deferred accounting treatment for expenses relating to Big Stone II. Four months later, in April 2010, OTP filed this rate case using a 2009 test year. The Commission then dismissed the deferred accounting docket so that the recovery request could be reviewed instead in the rate case.[19]

21. The Company expended $12,692,127 for development costs in connection with the Big Stone II project.[20] The Minnesota jurisdictional share of these costs is approximately half of the total.[21] The costs include engineering, project development, permitting, legal, other expenditures, and AFUDC. The Company excluded costs incurred for land in which OTP retains an ownership interest and internal labor costs that have been recovered in rates.[22]

22. OTP proposed to recover all of its Big Stone II development costs, with the exception of approximately $2.6 million attributable to the development of the transmission portion of the project, which it proposed to treat as an active project cost.

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[18] Ex. 14, Brause Direct at 26-28.
[19] *In the Matter of the Petition of Otter Tail Power Company Requesting Authority to Use Deferred Accounting for Costs Incurred During Its Participation in the Big Stone II Project*, Docket No. E017/M-09-1430, Order Approving Withdrawal (June 7, 2010).
[20] Ex. 14, Brause Direct at 15. This amount includes all transmission-related costs, which are discussed later in these Findings.
[21] *Id.*
[22] *Id*. at 28-29.

The Company proposed collecting the remaining costs over a five-year amortization period, with a return on the unamortized balance of the costs.[23] The Company alternately proposed a three-year amortization period if a return on the unamortized balance of the costs is not authorized.[24]

23. Although the OES participated in the CON proceeding and recommended approval of the transmission line with conditions, as well as approval of the Company's 2005 IRP, OES recommends in this case that cost recovery for Big Stone II expenses should be denied.[25] This adjustment would require a decrease in rate base of approximately $5,155,980 and a decrease in amortization expense of $1,288,995.[26]

24. The OAG also recommended denial of these costs.[27] MCC and Enbridge recommended that some portion of the costs be recovered without a return on the unamortized balance.[28]

A. The Used and Useful Doctrine.

25. The OES recommended that the Commission deny recovery of Big Stone II costs "because Minnesota law requires that utility plants be used and useful before cost recovery is allowed . . . ."[29] OES relies on Minn. Stat. § 216B.16, subd. 6, to assert that, because Big Stone II was not built, it could not be considered used and useful.[30]

26. Minn. Stat. 216B.16, subd. 6, requires the Commission to made "adequate provision for depreciation" of a utility's property "used and useful in rendering service to the public . . . ." but does not address the question of cost recovery for a project cancelled prior to construction.

27. The Commission has addressed the applicability of the "used and useful" doctrine in several cases, including the 1991 Northern States Power (NSP) rate case, and its request for ratepayers to pay for the costs of decommissioning the Pathfinder nuclear plant[31]; the 1981 NSP rate case involving cancellation of the Tyrone nuclear power plant in Wisconsin[32]; and the 1986 Otter Tail Power rate case in which OTP sought to recover the costs of its abandoned Spiritwood project.[33]

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[23] Ex. 15, Brause Rebuttal at 22.
[24] *Id.*
[25] Ex. 109, Rakow Surrebuttal at 8-9; Ex. 110, Lusti Direct at 13.
[26] Ex. 110, Lusti Direct at 13; Ex. 112, Lusti Revised Surrebuttal at 8.
[27] Ex. 59, Smith Direct at 50-91.
[28] Ex. 57, Schedin Direct at 11; Ex. 52, Erickson Direct at 18.
[29] Ex. 110, Lusti Direct at 10.
[30] *Id.*
[31] *In the Matter of the Application of Northern States Power Company to Increase Electric Rates*, Docket No. E-002/GR-91-1, Findings of Fact, Conclusions of Law and Order at 27 (Nov. 27, 1991).
[32] *Northern States Power Co. v. Minnesota Public Utilities Commission*, 344 N.W.2d 374 (Minn. 1984), *cert. denied*, *Humphrey v. Northern States Power Co.*, 467 U.S. 1256 (1982).
[33] Ex. 63, *In re the Petition of Ottertail Power Company for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-017/GR-86-380 (April 27, 1987) (*Spiritwood*).

28. The case involving the Pathfinder nuclear power plant is distinguishable from this one because that case involved an attempt to recover the costs of decommissioning a plant that was constructed but not used.[34] Development costs for the Tyrone project, which was not constructed, were mandated by an interstate agreement between Minnesota and Wisconsin and approved by the Federal Regulatory Energy Commission (FERC).[35]

29. In OTP's 1986 rate case, the Commission examined the question of whether and which costs the Company should recover from its abandoned Spiritwood co-generation project.[36] In that case, as in this one, the OAG and OES (then called the Department of Public Service, or DPS) opposed the inclusion of costs in rate base on the basis that the project was not used and useful in providing service.[37]

30. In its decision in *Spiritwood*, the Commission described its analytical framework:

> The decision to include abandoned property in rate base must meet the test of justice and reasonableness to the ratepayer as well as the investor. *Minneapolis Street Railway v. City of Minneapolis*, 86 N.W. 2d 657, 251 Minn. 43 (1957). The Commission must balance the interest of the ratepayer with the competing interest of the shareholder and, in its discretion, determine whether the ratepayer or investor will bear the loss of abandonment. The factors to be balanced in determining reasonableness include the used and usefulness of the abandoned property, the prudent cost of the property, and the sharing of the risk of abandonment between the investor and the ratepayer. The distribution of losses due to abandonment is a question of reasonableness under the circumstances of each case.[38]

31. The Commission found that the Spiritwood project was not used and useful, because the plant was not constructed and was, therefore, never in service. Nor were the Spiritwood costs reasonably necessary to the efficient and reliable provision of utility service. The Commission found:

> To consider such a nonexistent plant as used and useful is an unreasonable expansion of the used and useful concept. The plant in question has not provided and never will provide electricity to ratepayers.[39]

32. Accordingly, the Commission rejected the Company's proposal to include planning and engineering expense in rate base. It then turned to the question of whether OTP's investment in "land and other costs" for the Spiritwood project was

[34] Ex. 110, Lusti Direct, at 11.
[35] *Id*. at 12.
[36] Ex. 63, *Spiritwood* at 7.
[37] *Id.*
[38] *Id.* at 8.
[39] *Id.* at 8.

prudent and determined that it was not, because "OTP made large expenditures knowing that the project was dependent upon the participation of the [one] large industrial customer to make the . . . project feasible. Yet OTP did not choose to protect its investment with a firm contract . . . ."[40] These costs were also excluded from rate base.

33. In reaching this result, the Commission concluded that investors had been compensated for the risk of cancellation through the Company's allowed rate of return and that the risk of project abandonment is a normal business risk.[41] Although the Commission did not permit the Spiritwood project costs to be included in rate base, the Commission did not leave the Company without a recovery mechanism.

34. The Commission rejected the idea that, as a matter of principle, if a plant did not become used and useful, the expense recovery should be disallowed as well as the rate base treatment. "Rather, the Commission must look to the facts in the record and balance the ratepayers' and investors' competing interests."[42] The Commission then found that planning and engineering expenses incurred before the project was abandoned were prudently incurred. The Commission took into account the need for OTP to plan to meet forecasted needs, and found:

> [I]t is appropriate to allow recovery of such prudent planning and engineering costs because they were incurred in analyzing the decision to go forward . . . and in preparing for a certificate of need application. This treatment provides a reasonable sharing of the abandonment risk between the investor and the ratepayer which should assure the continuance of necessary planning and engineering costs in the future.[43]

35. The Commission allowed a ten-year amortization period for the costs of planning and engineering the Spiritwood project, despite the fact that no plant was ever built and the project was not found to be used and useful. The Commission chose ten years based on its own precedent and because no evidence was presented to persuade it that another amortization period was more appropriate.[44]

36. The Administrative Law Judge concludes that recovery of these costs should not be entirely precluded by the used and useful doctrine. It is reasonable in this case, as it was with regard to the Spiritwood project, to allow recovery of the planning and engineering costs as expenses that were prudently incurred.

B. Expense Recovery.

37. Recognizing that the Administrative Law Judge and the Commission might find that the circumstances pertaining to the Big Stone II project warrant allowing

[40] Ex. 63, *Spiritwood* at 9.
[41] *Id.* at 9.
[42] *Id.* at 18.
[43] *Id.* at 18.
[44] *Id.* at 18.

recovery of some of the Company's development costs, the OES recommended that the following questions be considered:

(1) whether any of the Big Stone II transmission costs should be set aside for future recovery;
(2) which costs should be eligible for recovery, external only, some other category, or all costs;
(3) whether OTP should be allowed to earn a return on the unamortized balance of the Big Stone ll costs; and
(4) what amortization period should be used to recover the costs.[45]

1. Exclusion of Transmission Cost.

38. The Company continues to pursue use of the proposed transmission lines developed as part of Big Stone ll as a multivalue project (MVP) within the jurisdiction of the Midwest Independent Service Operators (MISO). If the lines are approved for that purpose, they would primarily be utilized by wind farms, rather than by the Company's retail customers.[46]

39. If the transmission lines were defined as an MVP, under MISO's current proposed rate design, Minnesota ratepayers would pay only approximately 1% of the costs because OTP only has only about 1% of the load in the entire MISO transmission footprint.[47]

40. If the transmission lines were not to be granted MVP status, the Company would likely continue to move forward with utilizing the lines for wind farms and seek recovery of the transmission line costs in its next rate case.[48]

41. The amount attributable to transmission development costs could be as high as half of the total development cost of $12.7 million.[49] The MCC supports removal of half the development cost—approximately $6,346,000—from recovery in this case, to be treated as an active project cost and dealt with by MISO or in a future rate case.[50] But the amount allocated to transmission development in OTP's North Dakota rate case was approximately $2.6 million. Therefore, the Company proposed to move approximately $2.6 million of transmission-related costs back to its Construction Work in Progress (CWIP) account and to treat those costs as it would other transmission project costs.[51]

42. Removing the transmission costs and treating them as active project costs is consistent with the facts related to the projects. The Commission suspended, rather

[45] Ex. 63, *Spiritwood* at 16.
[46] Tr. 1:32-33, Brause.
[47] *Id.* at 32.
[48] *Id.* at 33.
[49] *Id.* at 30-31.
[50] MCC Initial Brief at 5.
[51] Ex. 15, Brause Rebuttal at 22.

than extinguished the Route Permit for the Big Stone II transmission facilities.[52] OTP acquired 100% of the rights necessary to develop the transmission facilities from the other Big Stone II participants in July of 2010[53] and has continued development activities for the transmission facilities.[54]

43. Because a "significant portion of the [Big Stone] II proceedings pertained to issues involving the generation facility rather than the transmission facility"[55] and the North Dakota Public Service Commission determined the transmission amount to be approximately $2.6 million,[56] the OES agreed that that amount is representative of the transmission-related costs.[57] Both OTP and the MCC agreed that the $2.6 million was sufficiently related to justify removal and deferral.[58]

44. The Administrative Law Judge agrees that it is reasonable to transfer $2.6 million of the proposed expense into CWIP, treating the Big Stone II transmission-related costs in the same way that other on-going project costs are treated.

2. Inclusion of Capitalized Internal Costs.

45. The OES and the OAG argued that, even if the Commission approves recovery of the cost of Big Stone II development, it should limit the recovery to the Company's external costs only (e.g., outside counsel, contractors, engineers, etc.) and not include internal labor and other costs.[59]

46. Although capitalized and non-capitalized labor and internal costs are typically recovered in a rate case, OES recommends that such costs not be permitted in this case because there is no "used and useful" facility.[60]

47. The Company demonstrated that its capitalized internal costs were excluded from current rates and, therefore, not recovered.[61] The Company explained that capitalized internal costs were accounted for in CWIP along with the other project costs, and that, in its last rate case, the CWIP costs were excluded from recovery through the use of the Allowance for Funds Used During Construction (AFUDC), which is a credit that increases the total available for return, reducing the revenue requirement. Thus, the long-term CWIP was excluded from the revenue requirements and rates.[62]

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[52] *Big Stone II CON*, Docket No. E017/CN-05-619, Order Extinguishing Certificate of Need, Suspending Route Permit, Providing for Permit Revocation, and Requiring Filings (Feb. 25, 2010).
[53] Ex. 15, Brause Rebuttal at 15.
[54] *Id.* at 17; Tr. 1:23, Brause.
[55] Ex. 112, Lusti Revised Surrebuttal at 10.
[56] Ex. 57, Schedin Direct at 12.
[57] Ex. 112, Lusti Revised Surrebuttal at 10.
[58] Ex. 58, Schedin Surrebuttal at 2-3.
[59] Ex. 110, Lusti Direct at 13; Ex. 112, Lusti Revised Surrebuttal at 11-12.
[60] Ex. 112, Lusti Revised Surrebuttal at 11-12.
[61] Ex. 34, Beithon Direct at 40-44.
[62] *Id.*

48. If OTP is permitted to recover its costs in the Big Stone II project, there is no meaningful basis to distinguish the treatment of internal costs from external costs. There is no evidence demonstrating that the Company's own employees assigned to work on Big Stone ll contributed less substantively than consultants or others the Company contracted with for the limited purpose of developing Big Stone ll. Public policy is not advanced by encouraging utility companies to look outside their own personnel as they develop significant new projects.

49. Nor is the used and useful doctrine relevant to the question of whether internal costs should be reimbursed. If the Commission decides that it is appropriate for the Company to recover its Big Stone ll development costs, those costs should include the Company's own legitimate and previously-unrecovered internal and external costs.

50. In addition, the OAG has argued that OTP improperly accounted for this expense in CWIP, because it should have booked those costs to FERC account 183, Preliminary Survey and Investigation Charges (PS&I).[63] It is unclear what ratemaking result would follow from this argument. In any event, OTP has established that these project costs fell within the definition of "construction" and were appropriately booked to CWIP.[64]

51. Finally, the OAG has argued that Big Stone II expenses exceeded amounts authorized by OTC's and OTP's Board of Directors, citing to minutes of Board meetings between 2005 and 2009. The minutes do not support the OAG's argument. They reflect Board approval of "additional" amounts to fund development costs, with no reference to the starting point or the total amount of expenses incurred to date.[65] The Administrative Law Judge cannot conclude that this issue has any ratemaking significance.

3. Return on Unamortized Balance.

52. The Company argued that it should receive a return on the unamortized portion of the expense if the recovery period is longer than three years. If a return on the unamortized balance is not authorized, the Company asserted, the amortization period can have a significant effect on the value of the costs authorized for recovery.[66] The longer the recovery period is extended, the larger the loss to the Company.[67]

53. The Company also asserted that the unique facts of this case support authorization of a return on the unamortized balance of costs because those costs were necessary for the numerous permitting proceedings through which the project was reviewed, and the costs were reasonably incurred and necessary for the serious consideration given to the project by regulatory agencies and the public. The Company pointed out that there has been no demonstration that its costs were prematurely

[63] Ex. 59, Smith Direct at 58-62.
[64] Ex. 15, Brause Rebuttal at 15; Ex. 36, Beithon Rebuttal at 47-49.
[65] Ex. 62, Smith Direct at RLS-32, pp. 10, 22, 32, 40, & 43.
[66] Ex. 15, Brause Rebuttal at 18-20.
[67] *Id.* at 18-19, citing Accounting Standards Codification 980-360-35.

incurred, excessive in amount, or unnecessary for the project's development. Therefore, it contends that recoveries should not be reduced by disallowance of a return on the unamortized balance of the costs.

54. OES, the OAG and the MCC opposed allowing a recovery of a return on the unamortized balance of the Big Stone II costs.[68] The MCC pointed out that shareholders would have shared in the rewards had Big Stone ll been completed; and that they should share in the risks as well, bearing some of the burden if the ratepayers shoulder the burden of development costs.[69]

55. The Administrative Law Judge concludes that the facts of this case are not so unique as to justify a return on the unamortized balance of costs. Allowance of a return on the unamortized balance of the expense is no different than allowing the inclusion of these costs in rate base, a result the Commission has not permitted. While the costs were reasonably incurred and necessary for the serious consideration given to the project by regulatory agencies and the public, the project was abandoned after considerable investment of resources by the Company, state agencies, and the Commission. As the Commission concluded with regard to *Spiritwood*, it is reasonable to ask the investors to share the burden of the costs of Big Stone ll with the ratepayers by bearing the diminishment in the value of the cost recovery over time. No return on the unamortized balance should be permitted.

4. Length of Amortization Period.

56. OTP pointed out that the North Dakota Public Service Commission (NDPSC) authorized a three-year amortization without a return on the unamortized balance of costs.[70] OTP proposed a five-year amortization period with a return on the unamortized balance. The five-year time period was based on the period of years over which the costs were incurred.[71]

57. OES acknowledged all of the possible amortization plans proposed by the parties. It suggested a five-year amortization period, without a return.[72] This would result in a decrease to rate base of $5,155,980 and a decrease in amortization expense of $343,115.[73] It also pointed out that the Commission could also consider a 10-year amortization period, based on its *Spiritwood* order.[74]

58. MCC recommended a 35-year amortization period.[75] The OAG recommended a 50-year amortization period for recovery of Big Stone ll costs, should

[68] Ex. 110, Lusti Direct at 13; Ex. 59, Smith Direct at 91; Ex. 57 Schedin Direct at 12-13.
[69] Ex. 57, Schedin Direct at 13.
[70] *Id*. at 12-13; and Ex. 45, NDPSC Approval of Settlement with Regard to the Big Stone ll Costs.
[71] Ex. 34, Beithon Direct at 39.
[72] Ex. 110, Lusti Direct at 13.
[73] *Id*.
[74] Ex. 112, Lusti Revised Surrebuttal at 13-14.
[75] Ex. 57, Schedin Direct at 6.

the Commission choose to allow such a recovery.[76] Each of these recommendations was based on projections of the life of the Big Stone ll plant, estimated at 35-50 years.

59. The Administrative Law Judge recommends a five-year recovery period for OTP's Big Stone ll costs, but with no return on the unamortized balance. It is reasonable to require investors to share some of the cost. But a ten-year period or longer is unreasonable, given that (unlike *Spiritwood*), OTP had little control over many of the factors that led it to withdraw from the project.

60. The Administrative Law Judge also recommends that, as suggested by the Company, the Commission order OTP to establish a tracker account to account for all recoveries and to establish a deferred credit account for any excess amounts recovered for Big Stone ll costs. The credit is to be reflected in the next general rate case after OTP recovers the total Big Stone ll project amount authorized for recovery.

II. ROLL IN OF WIND AND TRANSMISSION RIDERS INTO BASE RATES.

61. OTP has three wind projects for which it has been receiving cost recovery through its Renewable Resource Cost Recovery Rider (Renewable Rider): the 40.5 MW Langdon Wind farm,[77] the 48 MW Ashtabula Wind farm,[78] and the 49.5 MW Luverne Wind farm.[79]

62. In this case, OTP initially proposed to keep the cost recoveries for these projects in the Renewable Rider. In the course of the hearing, OTP, the OES and MCC have agreed that OTP should roll the renewable rider project costs into base rates. Enbridge and the OAG did not take a position on this issue. Rolling the renewable rider project costs into base rates will substantially increase OTP's rate base, but the bill impact to customers will be relatively neutral, given the corresponding reduction to the Renewable Rider rate.

63. Langdon is a wind farm located 10 miles south of Langdon in Cavalier County, North Dakota. OTP owns 27 of the 106 wind turbines at this location, each having a nameplate capacity of 1.5 MW for a total of 40.5 megawatts, along with real

[76] Ex. 59, Smith Direct at 91.

[77] *In the Matter of the Petition of Otter Tail Power Company to Establish a Renewable Resource Cost Recovery Rider and for Approval of 2008 Cost Recovery Factor*, Docket No. E-017/M-08-119, Order Approving Rider, Purchase Power Agreement, Variance, and Eligibility and Adding Requirements (Aug. 15, 2008).

[78] *In the Matter of Otter Tail Power Company's Annual Filing of it Renewable Cost Rider*, Docket No. E-017/M-08-1055, Order Approving Investment in Ashtabula Project Pursuant to Minn. Stat. Section 216B.1645, subd. 1, and as an Affiliated Interest (Jun. 16, 2009); *In the Matter of Otter Tail Power Company's Annual Filing of Renewable Resource Cost Recovery Rider and 2009 Cost Recovery Factor*, Docket No. E-017/M-08-1529, Order Approving Renewable Resource Cost Recovery Factor (Aug. 10, 2009).

[79] *In the Matter of Otter Tail Power Company's Petition for Approval of the Luverne Wind Project*, Docket No. E-017/M-09-883, Order Approving Investment in Affiliated Interest Project, with Clarifications (date); *In the Matter of Otter Tail Power Company's Request for Approval of its 2010 Renewable Resource Cost Recovery Adjustment Factor*, Docket No. E-017/M-09-1484, Order Approving 2010 Renewable Cost Recovery Factor and Requiring Rate Case Filing (Aug. 27, 2010).

property interests, tower foundations, operational equipment, and electric collection circuit lines. NextEra owns the remainder of the turbines and operates the entire wind farm. Initial operation began in December 2007, with the entire wind farm becoming commercially operational in January 2008.[80]

64. Ashtabula is part of a larger wind energy generation center, jointly developed by OTP and NextEra, consisting of a total of 138 wind turbines, each having a nameplate capacity of 1.5 MW. The project was constructed near Lake Ashtabula in Barnes County, North Dakota. OTP owns 32 of the 138 wind turbines for an aggregate nameplate capacity of 48 megawatts, along with real property interests, tower foundations, operational equipment, and electric collection circuit lines. NextEra owns the remainder of the turbines and operates the entire wind farm. Ashtabula became commercially operational by the end of 2008.[81]

65. Luverne is a wind generation project located in Steele County, North Dakota. The Luverne Project is part of a larger wind energy generation center called the Luverne Wind Energy Center. OTP owns 33 of 113 wind turbines with an aggregate nameplate capacity of 49.5 MW, tower foundations, operational equipment, electric collection circuit lines, project substation, approximately 13 miles of 230 kilovolt line, and real property interests. NextEra, through its subsidiary Ashtabula Wind II, LLC, owns the remaining interest in the Luverne Wind Energy Center, which became commercially operational in September 2009.[82]

66. There are a number of base rate components, including rate base and operating expenses, affected by moving these costs from recovery through the Renewable Rider to recovery through base rates.[83] The primary rate base components are: (i) gross plant in service; (ii) accumulated depreciation; and (iii) accumulated deferred income taxes.[84] The primary operating expense components are: (i) production expense; (ii) property insurance expense; (iii) depreciation expense; and (iv) general tax expense.[85] The agreement reached at the hearing provides that all interested parties will work with the Company to ensure that the transfer of recovery from the rider to base rates is correctly reflected in OTP's compliance filing.[86]

67. The Company agreed that the OES's recommended revenues and expenses for the roll-in are acceptable as outlined on Exhibit 105, Schedule NAC-S-8, and as explained at the evidentiary hearing.[87] As agreed, a credit for expected Production Tax Credits will be reflected in the base rates along with the other revenue requirement components.

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[80] Ex. 24, Sem Direct at 9.
[81] *Id*. at 9-10.
[82] *Id*. at 10.
[83] Ex. 35, Beithon Supplemental Direct at 3 and Schedules 2-b through 2-d (as corrected in OTP's August 12, 2010 Errata filing).
[84] *Id*.
[85] *Id*.
[86] Ex. 108.
[87] Tr. 3:115-117; Ex. 108 at 2-3; and Ex. 105, Schedule NAC-S-8.

68. Because the final determination of revenue requirements will depend on the timing of the implementation of final rates and the actual Renewable Rider collections that occur by then, an additional revenue requirement true-up amount will be reflected in OTP's compliance filing. The OES schedules included OTP's estimate of $800,000 for the true-up amount.

69. In addition, the Renewable Rider's tracker balance includes amounts being collected pursuant to the currently authorized Renewable Rider rate. The tracker balance (excluding the 48-month amortized recovery described below) is expected to be near zero by the time of the implementation of final rates in this case. But depending on the specific timing of final rates and the actual Renewable Rider revenues received by that time, the tracker balance may be negative (reflecting a Rider over-recovery) or positive (reflecting a Rider under-recovery). OTP's compliance filing will reflect the actual balance of the tracker at the time of final implementation to ensure no over- or under-recovery occurs.

70. The Renewable Rider will continue to be used to recover the approximately $4.2 million in costs that had been incurred prior to the test year and that were authorized for an amortized recovery over 48 months.[88] It will also continue to be used to recover future renewable project costs that the Commission determines are eligible for recovery through the Renewable Rider.

71. OTP proposed to classify these wind generation costs as 92 percent energy and 8 percent demand; OTP also proposed to allocate the demand-related costs based on upon the contribution to system peak of each customer class and to allocate the energy-related costs to classes based on the E8760 energy allocator. OES agreed with this allocation on the basis that OTP had filed specific requests to ensure that the wind from these facilities would count toward OTP's renewable energy standard (RES).[89] OES would not necessarily agree to this allocation if the Company acquires wind facilities beyond the level required to comply with the RES.[90]

72. In addition to the Renewable Rider described above, OTP also has a Transmission Cost Recovery (TCR) Rider.[91] Currently, there are two transmission projects which have been authorized for inclusion in the TCR Rider, and OTP proposed to include them both in base rates at the conclusion of this case, on the basis that their costs are known and stable and are well suited to base rate recovery.[92] The two projects are: (1) an upgrade of the 42-mile Appleton to Canby, Minnesota transmission

[88] Ex. 35, Beithon Supplemental Direct at 8; Ex. 108.
[89] Ex. 79, Ouanes Rebuttal at 2.
[90] *Id*.
[91] *In the Matter of Otter Tail Power Company's Request for Approval of a Transmission Cost Recovery Rider Including the Proposed 2010 Transmission Factor*, Docket No. E-017/M-09-881, Order Establishing Transmission Cost Recovery Rider and Approving Costs for Recovery (Jan. 28, 2010).
[92] Ex. 24, Sem Direct at 12.

line from 41.6 kV to 115 kV; and (2) an upgrade of the 35-mile Langdon to Hensel, North Dakota transmission line from 41.6 kV to 115 kV.[93]

73. The MCC proposed that the TCR Rider costs continue in the TCR Rider, on the basis that future transmission costs will be substantial as OTP adds transmission related to the Cap X 2020 project. MCC recommends that, if these costs are included in base rates, the addition of assets will be reviewed closely in each case and will not be presumed appropriate. While the impacts to other components are not as severe, because transmission does not currently include accelerated depreciation or production tax credits, the future impact of rider versus base rate treatment may become significant.[94]

74. The Administrative Law Judge recommends that the current TCR Rider costs be moved to base rates, as proposed by OTP. In its compliance filing implementing final rates, OTP will remove those costs from the TCR Rider, and adjust the TCR Rider rate and base rates accordingly.[95] To avoid double recovery during the interim rate period, OTP made an adjustment that removed the costs of those two projects from the interim rate revenue requirement. As part of the compliance filing, OTP should demonstrate that any costs included in the Test Year are not double counted, i.e., that any transmission costs included in the test year financials are not also being recovered through the TCR Rider.

75. The TCR Rider should remain available as a mechanism for truing-up any over- or under-recovery of costs collected through the time final rates become effective.[96] In addition, it should be used to recover any MISO-related Schedule 26 costs and any approved future transmission costs eligible for recovery in the TCR Rider.[97]

III. ALLOCATION OF COSTS OF 41.6 kV and 69 kV TRANSMISSION LINES.

76. Enbridge is a petroleum pipeline company with seven pumping stations located in OTP's service territory. It is OTP's largest customer, comprising 20 percent of OTP's Minnesota sales. Enbridge is served directly off of 115 kV lines, and it owns the transformer that reduces power from 115 kV to the 4 kV voltage used by Enbridge.[98] As a result, Enbridge is not charged for the cost of distribution facilities. In OTP's last rate case, and in this one, Enbridge has contended that OTP's lower-voltage lines (41.6 kV and 69 kV) should be classified as distribution, not transmission, facilities.

[93] Ex. 24, Sem Direct at 12.
[94] Ex. 57, Schedin Direct at 30-31.
[95] Ex. 24, Sem Direct at 12.
[96] *Id*. at 13.
[97] *Id*.
[98] Tr. 2:85, Erickson; Ex. 52, Erickson Direct at 1.

A. Background.

77. In *Order 888*, the Federal Energy Regulatory Commission (FERC) established open access principles designed to remove impediments to competition in the wholesale bulk power marketplace and to bring more efficient, lower cost power to the Nation's electricity consumers.[99]

78. The purpose of open access is to eliminate practices and constraints that impeded the ability to flow power between generators and utilities. FERC Order 888 also provided the genesis for regional transmission organizations, which eventually led to the development of the Midwest Independent System Operator (MISO).[100] MISO is responsible for operation and planning of the transmission network.

79. To assist in identifying the transmission facilities to which open access principles apply, *Order 888* established what is referred to as the FERC 7-Factor Test. The FERC 7-Factor Test identifies seven characteristics of distribution. The seven factors are:

> FERC Factor 1: Local distribution facilities are normally in close proximity to retail customers.
>
> FERC Factor 2: Local distribution facilities are primarily radial in nature.
>
> FERC Factor 3: Power flows into a local distribution system; it rarely, if ever, flows out.
>
> FERC Factor 4: When power enters a local distribution system, it is not reconsigned or transported to some other market.
>
> FERC Factor 5: Power entering into a local distribution system is consumed in a comparatively restricted geographic area.
>
> FERC Factor 6: Meters are based at the transmission/local distribution interface to measure flows into the local distribution system.
>
> FERC Factor 7: Local distribution lines will be of reduced voltage.[101]

80. FERC delegated the initial determination of what is distribution to the states, and it further authorized the states to establish additional characteristics as appropriate. In response, the Commission opened a docket and ultimately issued what

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[99] FERC Order 888, Docket Nos. RM-95-8-000 and RM 94-7-001.
[100] Ex. 119, Ferguson Direct at 3.
[101] *In the Matter of a Proceeding to Develop Statewide Jurisdictional Boundary Guidelines for Functionally Separating Interstate Transmission from Generation and Local Distribution Functions*, E-999/CI-99-1261, Order Adopting Boundary Guidelines for Distinguishing Transmission from Generation and Distribution Assets at p. 2, n.1 (July 26, 2000) (*Boundary Guidelines Order*).

is known as the *Boundary Guidelines Order*. The first guideline in the *Boundary Guidelines Order* provides:

> Lines with voltage of more than 50 kV are considered transmission assets unless demonstrated to be distribution assets after application of relevant factors. Lines with voltage of 50 kV or less are considered distribution assets unless demonstrated to be transmission assets after application of relevant factors. See Appendix A regarding "relevant factors." When load flow analysis is used to demonstrate the functional use of assets, it shall be done in conformance with Appendix B.[102]

81. Appendix A contains ten relevant factors, the first of which is the FERC 7-Factor test for identifying distribution. The remaining relevant factors are:

> (2) Is the facility installed only for the purpose of serving a particular "customer" (either generation or distribution)?
>
> (3) Does the facility serve wholesale load or other grouped load (e.g. retail load pockets), either in a looped or a radial configuration?
>
> (4) Was the facility designed to serve single phase load?
>
> (5) Was it jointly planned to meet load-serving needs of more than one utility? Are there contractual relationships designating its use?
>
> (6) What are the anticipated future uses of the facility? Is it planned to be looped?
>
> (7) Does the facility interconnect two or more utilities?
>
> (8) Who operates the line? Who performs maintenance and emergency repair? How is it operated on a normal and contingent basis?
>
> (9) What requirements does the facility meet under NESC design and maintenance codes?
>
> (10) What is the dominant functionality of the facility? If it is used for one purpose (e.g., transmission) most of the time, then it could be classified to that purpose.[103]

82. Appendix B provides that load-flow analysis may be used to determine the effect of simulated transactions on various facilities if done in conformance with Appendix B.[104]

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[102] *Boundary Guidelines Order* at Attachment (Boundary Guidelines).
[103] *Id*., Appendix A.

83. The Boundary Guidelines Order further provides:

> The Commission adopts the attached guidelines, together with Appendices A and B, for the purpose of determining the functional boundaries between the transmission and generation functions, and between the transmission and distribution functions. The Commission directs parties to use the guidelines and appendices in all future proceedings involving functional unbundling and other relevant proceedings.[105]

84. In OTP's last rate case, Enbridge and the Chamber questioned in direct testimony whether OTP's 41.6 kV and 69 kV lines qualified as transmission. In response, OTP in rebuttal filed what has been termed a "system study" using the *Boundary Guidelines Order*. In response to criticism by the Chamber, OTP conducted a study that divided its 41.6 kV and 69 kV lines into about 200 segments and analyzed those segments using the *Boundary Guidelines Order*. Enbridge and the Chamber objected to use of the study, observing that they lacked the necessary time to evaluate the study prior to the hearing.

85. The Commission concluded in that case that OTP had properly allocated the costs of its 41.6 kV and 69 kV transmission lines. Its order directed OTP to file a segment-by-segment study as part of its next rate case:

> While the record in this case fully supports the comprehensive findings of the Administrative Law Judge on allocating the costs at 41.6 kV and 69 kV transmission lines, the Commission will require the Company to file a fully developed study of its transmission system under the Boundary Order for examination in its next rate case. If no rate case is filed within the next five years, the Commission will require a filing to be examined on a stand-alone basis.
>
> The Company is planning to add substantial amounts of generation and transmission to its system within the next few years. These changes, combined with the ongoing evolution of technology, state energy policy, and the regulatory landscape, may affect the Company's transmission operations. It is important to have a detailed, segment-by-segment understanding of how that system operates to ensure that the principles and guidelines set forth in the Boundary Order continue to be properly applied.[106]

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[104] *Boundary Guidelines Order* at Appendix B.
[105] *Id.*, Ordering Paragraph 1 at p. 4.
[106] *In the Matter of the Application of Otter Tail Corporation d/b/a Otter Tail Power Company for Authority to Increase Rates for Electric Utility Service in Minnesota*, Docket No. E-017/GR-07-1178, Findings of Fact, Conclusions of Law, and Order at 20-21 (Aug. 1, 2008) (*Docket 07-1178)*.

B. The 2010 Segment Study.

86. In compliance with that directive, OTP filed a segment-by-segment study in this proceeding of all transmission, as well as substations. This study defines a line segment as the portion of a line between two switches. The study identified 2,261 line segments and applied the *Boundary Guidelines Order* to each segment.[107] Attachment 2 to the study is a spreadsheet description identifying how the factors were applied to each segment.

87. In applying the *Boundary Guidelines Order*, the Company found that its lines generally fall into one of four groups. The first group includes the vast majority of main lines that serve multiple communities, including distribution cooperatives, connecting transmission substations to transmission substations as the main line progresses from community to community. The second group is composed of lines that circle a large city and provide power to multiple substations serving the city, as well as providing power to communities outside the immediate geographical area. The lines in these first two groups were generally classified as transmission. The third group is composed of pure radial lines that extend from the main line and end at a transmission-level customer or a distribution substation. These were classified as distribution lines. The final group consists of a radial line that ends at a substation that is connected to a generator. OTP concluded that because the generator provides a separate source of power and from a reliability standpoint eliminates the radial nature of the line, these lines were classified as transmission. A radial line that connects the generator to the substation, however, was considered a generation asset.[108]

88. OTP's study concluded that 117 of 3,756 total miles of 41.6 kV lines were properly classified as distribution, and 3,639 were properly considered transmission. Of the 211 total miles of 69 kV lines, approximately 6 miles were considered distribution and the remaining lines were classified as transmission. OTP also concluded that approximately 6 miles of 115 kV lines, out of 211 total miles, should be classified as distribution.[109]

89. The results of this study were incorporated into the Company's jurisdictional cost of service study (JCOSS), the class cost of service study (CCOSS), and the rate base schedules presented in this case. The changes reflected in this study (as compared to the one filed in the previous case) reduced the Minnesota jurisdictional revenue requirement by approximately $22,400.[110]

90. Enbridge has not taken issue with OTP's classification of any particular segment of line contained in the study. It agrees that the categorization of OTP's lines should be determined by applying the *Boundary Guidelines Order* and that the *Boundary Guidelines Order* should serve as the basis for cost allocation. It asserts,

[107] Ex. 13, *Boundary Guidelines Order* at 3-4 of 111.
[108] Ex. 31, Rogelstad Direct at 9-10.
[109] *Id*. at 10.
[110] *Id*. at 13.

however, that OTP has improperly analyzed the *Boundary Guidelines Order* and that the results of the study should be rejected.[111]

91. Enbridge argues that OTP's first error in the 2010 Study is "discounting the manner in which its facilities function;" second, it argues that OTP failed to conduct any load flow tests; third, OTP's analysis is too narrowly focused; fourth, OTP misapplied the FERC Seven Factors; and fifth, it argues OTP misapplied the Relevant Factors in the *Boundary Guidelines Order*.

1. Operating Normally Open.

92. Enbridge's first argument is that OTP "discounted the manner in which its facilities function." Enbridge contends that, when a line operates normally open, it is distribution.[112] This recommendation is based largely on Minnesota Power's practice of assuming, in classifying its lines, that where lines contained a switch designated on the system as "normally open," the line was radial at least 95% of the time, would not participate in regional flows, and would not provide meaningful benefit to users of the transmission system.[113] Enbridge contends that, by disregarding the normal operation of its 41.6 kV and 69 kV facilities, OTP failed to comply with the *Boundary Guidelines Order*.

93. The record reflects that 87 percent of OTP's 41.6 kV, 100 percent of its 69 kV lines, and 20 percent of its 115 kV lines operate normally open;[114] however, OTP's integrated transmission system is planned and constructed in a looped configuration (meaning electricity can flow from either side of an open breaker or switch). Looped facilities have breakers that can be closed or opened at transmission substations and at switches. When the breakers and switches are closed, electricity can flow across the breaker; when the breakers and switches are open, electricity cannot flow. OTP's 41.6 kV and 69 kV facilities tend to be long because they serve small towns that are far apart. Keeping a breaker or switch open limits the impact of disruptions on one segment of the facility and promotes reliability. Because the system is looped, however, OTP can open a breaker or switch if necessary and electricity can flow to all parts of the loop.[115] Some switches have remote control capability and can be closed electronically, while others have to be closed physically. Some switches have sensors that close the switch automatically.[116]

94. The low load densities in OTP's service territory allow it to operate most of its 41.6 kV and 69 kV facilities in a normally open configuration; in areas with higher load densities, the demands on the transmission system will not permit the system to be operated normally open. Utilities serving largely rural areas, like OTP and MDU Resources Group, rely heavily on lower voltage transmission. Utilities with a mixed load

[111] Enbridge Brief at 5.
[112] Ex. 119, Ferguson Direct at 10; Ex. 123, Ferguson Surrebuttal at 11.
[113] Ex. 119, Ferguson Direct at 7.
[114] Ex. 33, Rogelstad Rebuttal at 25.
[115] *Id*. at 24-25.
[116] Tr. 3:198-99, Rogelstad.

pattern, like Great River Energy, rely more heavily on 69 kV lines, while utilities with a higher load density (Minnesota Power and Xcel Energy) rely more heavily on 115 kV lines.[117]

95. The Company has established that this "normally open" configuration on the lines in question is based largely on the low load density of much of its service territory, and that in and of itself, the characterization of a line as "normally open" does not resolve the question whether the line is transmission or distribution. Regardless of Minnesota Power's practice with regard to classifying lines in its service territory, no provision of the *Boundary Guidelines Order* requires OTP to consider any line that operates normally open as distribution. The Administrative Law Judge concludes that OTP's failure to classify "normally open" lines as distribution does not violate the *Boundary Guidelines Order* or invalidate the results of OTP's study.

2. Load Flow Tests.

96. Second, Enbridge argues that OTP's failure to conduct any load flow tests is a violation of the *Boundary Guidelines Order* and invalidates the results of OTP's study. Enbridge contends that "simply looking at line segments" is insufficient to overcome the presumption in the *Boundary Guidelines Order* that lines less than 50 kV are to be considered distribution, unless application of the Relevant Factors demonstrates otherwise. It points out that Minnesota Power used load flow studies to determine regional or interstate impact in classifying some of its 115 kV lines. Enbridge argues that OTP's failure to use this level of rigor is a significant and fatal flaw in the Company's analysis.[118] In addition, it argues that OTP's discovery responses, which used a model to predict flow impacts in response to various scenarios requested by Enbridge, demonstrate that the Company's 41.6 kV system "does not meaningfully participate in regional flows" or wholesale bulk power markets.[119]

97. OTP did not conduct load flow tests in the course of its study, because it did not believe such tests were necessary.[120] It pointed out that each line segment analyzed in its study, because of its looped configuration, has the ability to flow power in either direction depending on system conditions.[121] Moreover, it argues that the *Boundary Guidelines Order* does not require it to demonstrate that its lines participate in either regional or interstate flows of power, since all transmission (by FERC definition) involves interstate commerce.[122]

98. The Company acknowledges that its 41.6 kV facilities were designed to serve OTP and its interconnecting utilities, not other regions. It argues, however, that these facilities were built economically many years ago for the purpose of transmission, and the fact that there are now much larger lines moving power across regions, and that

[117] Ex. 31, Rogelstad Direct at 18.
[118] Ex. 119, Ferguson Direct at 10.
[119] Ex. 123, Ferguson Surrebuttal at 11.
[120] Tr. 3:205, Rogelstad.
[121] Ex. 33, Rogelstad Rebuttal at 22.
[122] *Id*.

MISO is now in the process of developing regional transmission rates, does not change the function of its lower-voltage lines or require their reclassification as distribution.[123] Nor does it change the fact that its 41.6 kV facilities are used to connect approximately 110 MW of generation to the transmission grid, which is the reason why open access principles were developed.

99. The *Boundary Guidelines Order* does not require a load flow analysis. It provides only that, if a load flow analysis is used to demonstrate the functional use of assets, it shall be done in conformance with Appendix B. Appendix B provides that "[l]oad flow analysis may be used to determine the effect of simulated transactions on various facilities if done in conformance with the following guidance."[124] The Administrative Law Judge concludes that OTP's failure to conduct a load flow analysis does not violate the *Boundary Guidelines Order* or invalidate its study. In addition, Enbridge offers no compelling reason why a utility that serves such a large, low-density service area should have to demonstrate a particular level of participation in regional or interstate flows, if its lines otherwise meet the criteria for classification as transmission assets.

3. Narrow Focus on Segments.

100. Third, Enbridge argues that the Company's 2010 study is too narrowly focused on evaluating separate line segments, as opposed to examining the operational context of those facilities under normal conditions. It argues that breaking down lines into segments between switches and taps, and assessing each segment as either transmission or distribution, misses the point of the classification process.[125]

101. This is essentially the same argument made above, which is that only a load flow analysis will adequately demonstrate whether a facility participates in regional or interstate flow of power. The Company provided a segment-by-segment study because that is what the Commission ordered it to do in the last case, based on the arguments of the parties. OTP has applied the relevant factors contained in the *Boundary Guidelines Order* to each segment. The use of a segment-by-segment analysis does not violate the *Boundary Guidelines Order* or invalidate the study.

4. Application of FERC Factors.

102. Fourth, Enbridge argues that OTP misapplied the FERC 7-Factor test in a variety of ways. Many of Enbridge's arguments with regard to the FERC 7-Factor test are variants of its arguments described above regarding the classification of "normally open" facilities and the absence of load flow studies.

103. **FERC Factor 1.** Enbridge argues that under FERC Factor 1, OTP should have found that its facilities are in "close proximity" to customers. Enbridge contends

[123] Ex. 33, Rogelstad Rebuttal at 34.
[124] *Boundary Guidelines Order* at Attachment & Appendix B.
[125] Ex. 119, Ferguson Direct at 10.

that rural utilities should define "close proximity" differently than do utilities that serve densely populated urban areas.[126]

104. OTP applied this factor by determining whether OTP load was connected to a line segment; a "yes" response indicated that some load was connected to the line segment, while a "no" indicated that that no load was connected to the segment. If the line segment was basically a switch or bus, and the line section was ultimately determined to be transmission, then OTP did not answer the remaining columns because the switch was considered a transmission asset.[127]

105. OTP provided evidence that its typical 41.6 kV line is 68 miles long and has 13 transmission substations connected to the line. These 13 substations in turn serve the distribution substations providing retail service. The geographic area supported by this typical 41.6 kV line is more than 400 square miles. OTP's largest distribution system, in contrast, covers 15 square miles; it has many distribution systems that cover less than 1 square mile.[128]

106. Enbridge has not offered a specific definition that should be applied here. It appears Enbridge would use mileage, as opposed to connection to load, to determine proximity to customers.

107. The Administrative Law Judge concludes OTP did not err in applying FERC Factor 1 in determining whether line segments were in close proximity to customers. OTP's definition is clearly intended to differentiate transmission from distribution.

108. **FERC Factor 2.** Enbridge argues that OTP misapplied FERC Factor 2, which describes local distribution facilities as being "primarily radial in nature." Enbridge argues that lines that are operated normally open should be classified as radial lines and accordingly considered to be distribution. It suggests that because the North American Electric Reliability Corporation (NERC) excludes radial lines from the definition of bulk transmission, a similar result should follow here.[129]

109. OTP's study defined a radial line as one for which power typically flows in one direction; if power can flow from either direction, it was classified as transmission.[130] This is consistent with OTP's conclusion that a true radial line ends; there is nothing tied to it other than load.[131] OTP classified all lines that terminated at a distribution substation or customer as distribution.[132]

110. The record reflects that a normally open line is not necessarily radial in nature, and the NERC definition of "bulk transmission" is irrelevant to the application of

[126] Ex. 124, Sherner Direct at 10.
[127] Ex. 13, Attachment 2 at p. 3.
[128] Ex. 33, Rogelstad Rebuttal at 29.
[129] Ex. 124, Sherner Direct at
[130] Ex. 13, Attachment 2 at 3-4.
[131] Tr. 3:202, Rogelstad.
[132] Ex. 31, Rogelstad Direct at 14.

the FERC factors, which are used for a different purpose. The Administrative Law Judge concludes that OTP's definition of a radial line is appropriate and that OTP did not misapply FERC Factor 2.

111. **FERC Factor 3.** FERC Factor 3 provides that power flows into a local distribution system; it rarely, if ever, flows out. Enbridge argues that because most of OTP's 41.6 kV and 69 kV facilities are operated normally open, power typically flows in one direction, and they should be considered distribution. In addition, Enbridge argues that, absent any load flow tests, OTP has failed to prove that power physically flows out of its 41.6 kV and 69 kV facilities.[133]

112. OTP's study used the same definition for this factor as for defining radial facilities—if power typically flows in one direction, it is distribution, but if power can flow from either direction, it is transmission.[134] For the reasons described above, the Administrative Law Judge concludes that this definition was appropriate and that OTP did not misapply FERC Factor 3.

113. **FERC Factor 4.** FERC Factor 4 provides that "When power flows into a local distribution system, it is not reconsigned or transported to some other market." Enbridge characterizes this factor as being intended to determine whether power is flowing from other markets "from the interstate commerce perspective."[135] This is essentially the same argument made above with respect to regional or interstate power flow. The example provided by Enbridge is Basin Electric selling to Xcel Energy in the Twin Cities, or OTP selling power from Big Stone to a power marketer for delivery in Chicago. In Enbridge's view, only high-voltage transmission is used for delivery of power to other markets.[136]

114. OTP's system is designed to transfer power for multiple utilities over the 230 kV, 115 kV and also 69 kV and 41.6 kV facilities.[137] OTP analyzed this factor by identifying whether other utilities possibly had power moving across a segment of line. If no other utility had power moving through the segment, it was answered "no" in the study.[138]

115. The *Boundary Guidelines Order* makes FERC Factor 4 a relevant factor in distinguishing between transmission and distribution in any utility's system, not just those moving power on high-voltage lines from one state to another. Factor 4 is designed to identify a distribution asset by focusing on whether power is reconsigned or transported to another market after flowing into the facility. OTP interprets "another market" more broadly than Enbridge, to include other utilities. The definition is reasonably calculated to ensure that load on segments considered to have transmission characteristics is not being delivered to a customer but moves elsewhere after it flows

[133] Enbridge Proposed Findings of Fact at 17.
[134] Ex. 13, Attachment 2 at 4.
[135] Ex. 124, Sherner Direct at 11.
[136] *Id*.
[137] Ex. 33, Rogelstad Rebuttal at 10.
[138] Ex. 13, Attachment 2 at 4.

through the facility. The Administrative Law Judge concludes that OTP has not misapplied this factor.

116. **FERC Factor 5.** FERC Factor 5 provides that "power entering a distribution system is consumed in a comparatively restricted geographic area." Enbridge again argues that the definition of a "comparatively restricted geographic area" should be different for a utility serving sparsely populated areas than for a utility serving densely populated urban areas. Enbridge argues that the primary purpose and function of OTP's typical 41.6 kV lines—the length of which is about 68 miles—is to supply power that is consumed in that "slightly enlarged restricted geographic area." In Enbridge's view, this makes the lines distribution.[139]

117. It is difficult to conclude that a 68-mile facility that supports a 400-square mile area should be considered a restricted geographic area. OTP's study answered "yes" to this question if power from a segment flows to a local area or to a town ringed with multiple line segments to serve it.[140] OTP's application of this factor does not appear to be intended to skew the results in favor of finding lines to be transmission. The Administrative Law Judge concludes OTP has not misapplied FERC Factor 5.

118. **FERC Factor 6.** FERC Factor 6 provides that "meters are based at the transmission/local distribution interface to measure flows into the local distribution area." Enbridge argues that Factor 6 is intended to note points of demarcation between independent transmission providers and customers or separately owned local distribution providers. Because OTP owns both the transmission and distribution facilities, Enbridge maintains the factor is inapplicable.[141]

119. OTP's study did not answer this question with a yes or no response; it identified whether a metering point was located near the segment, and if so, where.[142] If Enbridge is correct and this factor is irrelevant because OTP owns both the transmission and distribution facilities, Enbridge does not articulate how OTP's application of it has influenced the study results, nor does it identify any segments that were improperly classified based (even partially) on application of this factor. On this record, it does not appear to the Administrative Law Judge that OTP misapplied this factor.

120. **FERC Factor 7.** Finally, FERC Factor 7 provides that "local distribution lines will be of reduced voltage." The FERC Order did not elaborate on the meaning of "reduced voltage." In a different section of the order, however, FERC provided a summary of then-current practices, which provides "it appears that utilities account for facilities operated at greater than 30 kV as transmission and distribution facilities are usually less than 40 kV."[143]

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[139] Ex. 124, Sherner Direct at 12.
[140] Ex. 13, Attachment 2 at 5.
[141] Enbridge Initial Brief at 10.
[142] Ex. 133, Attachment 2 at 5.
[143] Ex. 31, Rogelstad Direct at 7-8; and FERC Order 888, Appendix G, n. 100.

121. Enbridge contends that 41.6 kV and 69 kV lines are of "low voltage" compared to the 345kV and 500 kV lines in the regional grid and the 765 kV systems further east.[144] OTP's study answered "no" to this question because only 41.6 kV facilities and larger were reviewed. It does not appear to the Administrative Law Judge that there is supposed to be one correct answer to the question whether a facility is "low voltage." In the context of OTP's integrated system, the density loads it serves, and the rural nature of its service territory, 41.6 kV and 69 kV lines are not low voltage. It does not appear that OTP misapplied this factor.

5. Application of Other Relevant Factors.

122. Enbridge did not dispute OTP's application of Relevant Factor 2, and it contends that several of the other Relevant Factors identified in the *Boundary Guidelines Order* are not, in fact, relevant and have no meaningful bearing on this case.[145] Enbridge disputes the application of Relevant Factors 3, 5, 6, 7, and 10.

123. **Relevant Factor 3.** Relevant Factor 3 asks: "Does the facility serve a wholesale load or other grouped load (e.g., retail load pockets), either in a looped or a radial configuration?" Enbridge argues that this factor addresses only a wheeling situation, or an Integrated Transmission Agreement (ITA) in lieu of wheeling. It argues that service of wholesale load does not represent either a transmission or distribution function, but indicates only that FERC has jurisdiction over the wheeling service or the ITA agreement.[146]

124. OTP applied this factor by determining whether other utility substations are located along the main line or at the end of the main line. If there were other utility substations, it identified the utility.[147]

125. The *Boundary Guidelines Order* by its own terms requires examination of whether the facility serves wholesale or other grouped load. OTP's facilities are part of an integrated transmission network, interconnecting with four other utilities and serving the loads of distribution cooperatives.[148] The Administrative Law Judge concludes that OTP did not misapply Relevant Factor 3.

126. **Relevant Factor 5.** Relevant Factor 5 asks: "Was it jointly planned to meet load-serving needs of more than one utility? Are there contractual relationships designating its use?" Enbridge argues that efforts to jointly plan with other utilities do not make the facilities transmission as opposed to distribution.[149]

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[144] Ex. 124, Sherner Direct at 12.
[145] *Id*. at 12-14. Enbridge asserts that the irrelevant factors are 4 (41.6 and 69 kV lines are not single phase); 8 (the identity of the entity that operates and maintains a facility has little bearing on its classification); and 9 (all OTP facilities meet NERC design and maintenance codes).
[146] Ex. 124, Sherner Direct at 12.
[147] Ex. 13, Attachment 2 at 6.
[148] Tr. 3:207-08; Ex. 33, Rogelstad Rebuttal at 10, 28.
[149] Ex. 124, Sherner Direct at 13.

127. Many of OTP's 41.6 kV lines are integrated with Great River Energy, Minnkota Power Cooperative, Central Power Electric Cooperative, East River Electric Cooperative, as well as the Western Area Power Administration.[150] OTP has four ITAs, under which OTP and the cosigners (CPEC, GRE, Minnkota, and MRES) jointly plan and construct transmission facilities, including 41.6 kV and 69 kV facilities, for the mutual benefit of the parties and for the benefit of economically and reliably serving the parties' communities.[151] OTP's study identifies utilities other than OTP that are served along a main line.[152] The Administrative Law Judge concludes OTP did not misapply Relevant Factor 5.

128. **Relevant Factor 6.** Relevant Factor 6 asks: "What are the anticipated future uses of the facility? Is it planned to be looped?" According to Enbridge, "looped" should mean closed and operating as an integral part of and in parallel to the rest of the network. "Looped" but operating normally open should mean the facility is radial.[153]

129. This factor allows the categorization of a facility to be based on future plans for the facility rather than its current operation. OTP argues that this factor supports its position that its facilities (which are *always* looped but operated normally open) can still be considered transmission. In its study, OTP identified only one line within its system that is radial but was designed to be looped in the future (a 115 kV line).[154] For the reasons stated above with regard to Enbridge's "normally open" argument, the Administrative Law Judge concludes OTP did not misapply Relevant Factor 6.

130. **Relevant Factor 7.** Relevant Factor 7 asks: "Does the facility interconnect two or more utilities?" Enbridge again argues that OTP's intertwined service territory justifies prudent planning with other facilities, but that consideration should not impact the function of assets. [155]

131. As noted above, many of OTP's 41.6 kV lines are integrated with GRE, Minnkota Power Cooperative, Central Power Electric Cooperative, East River Electric Cooperative, as well as the Western Area Power Administration.[156] OTP's study addressed this factor by identifying any utility that was interconnected at the end points of the main line or has load within the main line.[157]

132. It is apparent that Enbridge disagrees with the relevance of many of the factors identified in the *Boundary Guidelines Order*, but it has turned this disagreement into a series of unfounded arguments that the Company has misapplied the factors. It

[150] Ex. 31, Rogelstad Direct at 17.
[151] *See* Attachment P to the MISO Tariff. These contracts include GRFA Nos. 297 (CPEC-1958), 306 (GRE-1967), 314 (Minkota-1962), and 318 (MRES-1986).
[152] Ex. 13, Attachment 2 at 6.
[153] Ex. 124, Sherner Direct at 13.
[154] Ex. 13, Attachment 2 at 6.
[155] Ex. 124, Sherner Direct at 13.
[156] Ex. 31, Rogelstad Direct at 17.
[157] Ex. 13, Attachment 2 at 6-7.

appears to the Administrative Law Judge that the Company has applied Relevant Factor 7 in the manner contemplated by the *Boundary Guidelines Order*.

133. **Relevant Factor 10.** Relevant Factor 10 asks: "What is the dominant functionality of the facility? If it is used for one purpose (e.g. transmission) most of the time, then it could be classified to that purpose." This factor calls for a conclusion with regard to the segment's function based on the overall analysis.[158] Enbridge contends that the dominant functionality of the 41.6 kV and 69 kV lines operated normally open is serving load, not providing "instantaneous parallel capability to the power grid." Because OTP's substation analysis is based in large part on the classification of the lines emanating from the substation, Enbridge asserts that a significant number of substations should be reclassified as combination substations, with investments split between transmission and distribution.[159]

134. Under Enbridge's interpretation of all the factors, only major load centers would be connected to transmission. As a result, only those utilities and generation sources serving large load centers would obtain the benefits of open access, and the rural towns in Minnesota and elsewhere would be served by distribution, not transmission facilities. The Administrative Law Judge can see nothing in the *Boundary Guidelines Order* that would compel this result.

135. OTP has performed the study required by the Commission. The Administrative Law Judge concludes the Company has rebutted the presumption that most of its 41.6 kV lines are to be considered distribution assets through application of the Relevant Factors. The Company has also demonstrated, by application of the Relevant Factors, that virtually all of its 69 kV lines function as transmission. The Administrative Law Judge recommends that the Commission accept the study as filed.

136. In testimony, Enbridge requested that the Commission require an independent review of the 2010 Segment Study. It did not make such a request in its closing briefs. If Enbridge has not dropped this issue, the Administrative Law Judge recommends that the Commission deny this request.

137. Enbridge also requested that the Commission recommend a FERC audit of OTP's FERC Form 1 reports. The concerns identified by Enbridge do not impact jurisdictional allocations and have no impact on Minnesota retail rates. The Administrative Law Judge does not believe it is necessary for the Commission to request an audit.

138. If the Commission were to accept Enbridge's arguments, OTP would lose the current revenues and investment credits it receives under existing ITAs for use of its lower voltage transmission facilities by other utilities. OTP estimated an additional net loss (in this rate case) of approximately $1.7 million based on all changes in revenues and expenses. When the existing ITAs expire in a few years, the net loss would begin

[158] Ex. 13, Attachment 2.
[159] Ex. 124, Sherner Direct at 14.

to increase in 2015 to approximately $3.2 million.[160] Enbridge claims OTP would be able to replace lost transmission revenue with a FERC-filed distribution tariff (although its witnesses contradict each other on this point). It is not at all clear whether the changes proposed by Enbridge would be revenue-neutral to the Company.

139. There would also be financial consequences to OTP's ITA counterparties. GRE and MRES filed public comments opposing changing the categorization of these facilities.

140. In addition, there would be increased costs and barriers for distributed generation and wind generation.[161] A wind generator's costs would increase, as it would need to pay both the MISO transmission rate and an OTP distribution rate.[162]

141. Moreover, such changes would impact this rate case in a number of ways. The Minnesota jurisdictional revenue requirement would be reduced by approximately $774,484; the costs charged to the LGS class would be reduced by $1,199,973; the costs charged to North Dakota and South Dakota would increase by $774,484; and the costs allocated to all other Minnesota customer classes would increase by $425,489.[163]

C. Stratification of Transmission.

142. In the event the Commission accepts OTP's 2010 Segment Study, Enbridge requests that the Commission stratify OTP's transmission facilities into high-voltage facilities (above 100 kV) and low-voltage facilities (100 kV or less) and that it should not be assigned cost responsibility for low-voltage transmission in the CCOSS. It would accomplish this through incorporation of a revised D-2 allocation factor into the CCOSS, which would have the same general impacts described above on the JCOSS and CCOSS.[164] Under this proposal, however, OTP would not lose the existing ITA and MISO revenues ($1.7 million growing to $3.2 million) paid by other utilities for use of the facilities, and wind generation and distributed generation would not be disadvantaged.

143. Enbridge acknowledged that, as the only transmission customer served directly off of a 115 kV line, the full benefit of these changes, from a cost of service basis, would be credited to Enbridge.[165]

144. The 1992 NARUC manual recognizes two methods for allocating transmission costs: rolled-in rates and stratification as transmission and subtransmission. The NARUC manual states:

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[160] Ex. 33, Rogelstad Rebuttal at 16-17.
[161] *Id*. at 12.
[162] Ex. 55, Erickson Surrebuttal at 7.
[163] Ex. 52, Erickson Direct at 17. Although these calculations were originally performed to determine the impact of Enbridge's proposal to subfunctionalize transmission, Enbridge agrees that the impacts of the two proposals would be similar. *See* Tr. 2:95-96, Erickson.
[164] Ex. 52, Erickson Direct at 17.
[165] Tr. 2:99-100.

> Under the rolled-in transmission method of functionalization, the transmission system is comprised of highly integrated facilities which are designed and operated collectively to deliver bulk power supply from point to point on the system. Thus, where facilities of various operating voltages form integrated transmission networks, each element within those networks is considered to be contributing to the economic and reliable operation of the system as a whole.
>
> … Therefore, since all customers are generally expected to benefit from the strategy of overall transmission cost minimization, all should be expected to share the costs of the system.[166]

145. Under the stratification method, high-voltage transmission costs are assigned to all customers, while all lower-voltage costs are assigned to customers located downstream from the high-voltage facilities.[167]

146. In 1980, OTP asked FERC to approve its use of a rolled-in rate when customers asked to have lower-voltage facilities stratified into a different rate. FERC found that OTP operates an integrated transmission system and, consequently, determined that rolled-in rates should apply:

> Commission precedent strongly favors use of the rolled-in method of transmission allocation. Given a finding that the system operates as an integrated whole, transmission costs have generally been rolled-in, absent a finding of special circumstances. The principal reason behind adoption of this methodology is that an integrated system is designed to achieve maximum efficiency and reliability at a minimum cost on a system-wide basis. Implicit in this theory is the assumption that all customers, whether they be wholesale, retail, or wheeling customers, receive the benefits that are inherent in such an integrated system. Otter Tail has such an integrated system. In fact, the evidence shows that Otter Tail and the other utilities in its area have made extensive efforts to produce a fully integrated system in the interest of efficiency and reliability. It is our conclusion that the record before us does not merit deviation from the rolled-in methodology of transmission cost allocation.[168]

147. The integrated nature of OTP's transmission system has not changed since this decision was made in 1980. Rolled-in rates remain the policy preference of FERC, MISO, North Dakota, and South Dakota.[169]

148. It is a common-sense proposition that in an integrated system, lower-voltage facilities can provide support to higher-voltage facilities in the event of an outage. OTP provided evidence to support the proposition in the example of a

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[166] Ex. 33, Rogelstad Rebuttal at 30; Electric Utility Cost Allocation Manual (January, 1992) at 71.
[167] *Id*.
[168] 12 FERC ¶ 61,169 at 61,420 (1980); Ex. 33, Rogelstad Rebuttal at 32.
[169] Ex. 33, Rogelstad Rebuttal at 33-34.

hypothetical outage of the 115 kV line between Wilton and Bemidji. With this facility out of service, the loads in the Bemidji area (including the Enbridge load near Cass Lake) would have to be served from a transmission substation near Park Rapids. Because of the long distance, voltages at peak load conditions would be unacceptable in the Bemidji area. In order to restore voltages at Cass Lake to acceptable levels, the 41.6 kV and 69 kV facilities between Wilton and Bemidji must be used. This would be achieved by closing a normally open breaker on the 69 kV line and a 41.6 kV switch. By using these lower-voltage facilities, NERC reliability criteria would be met.[170]

149. Enbridge's proposal allocates the cost of high-voltage transmission facilities based on system demand, but it allocates the cost of downstream facilities based on the demand served off of the lower-voltage facilities. This methodology effectively determines the cost of service based on the location of the load served. Approximately 50 percent of OTP's Minnesota load is served off of high voltage facilities, and 50 percent of the OTP's Minnesota load is served off of downstream facilities. According to Enbridge, the downstream customers would pay for both the low-voltage and high-voltage facilities, while upstream customers would pay only for the high-voltage facilities.[171] Under this policy, rural customers would pay higher rates than urban customers; and each customer class would have two different rates, upstream and downstream.[172] In addition, if this rate structure were implemented, a wind generator interconnecting on a subtransmission line would pay a higher cost than one interconnecting with a 115 kV line.[173]

150. This is a rate design issue, which the Commission will resolve largely on policy, not factual, grounds. In OTP's last rate case, the Commission rejected an identical argument to discontinue the use of rolled-in rates in favor of stratified transmission rates.[174] For the reasons articulated in the 1980 FERC order and by the Commission in the last rate case, the Administrative Law Judge recommends that the Commission retain the current rolled-in rate structure and decline to implement the stratification proposal made by Enbridge.

IV. JURISDICTIONAL AND CLASS COST OF SERVICE STUDIES.

A. Equivalent Peaker Method.

151. OTP operates in Minnesota, North Dakota, and South Dakota, and is under FERC jurisdiction for wholesale transactions. To fairly apportion costs among multiple jurisdictions, utilities use a JCOSS. To apportion costs between classes of customers within a jurisdiction, a CCOSS is used.

152. OTP used the equivalent peaker method to allocate production costs between demand and energy in both its JCOSS and CCOSS. Under the equivalent

[170] Ex. 33, Rogelstad Rebuttal at 48.
[171] Tr. 2:82, Erickson.
[172] *Id*.
[173] Ex. 33, Rogelstad Rebuttal at 12, Ex. 123 Ferguson at 8.
[174] *Docket 07-1178* Order at 66-67.

peaker method, OTP allocates demand-required costs using a demand allocator (kW basis) and allocates energy-required costs using an energy allocator (kWh basis). This method results in approximately 75% of fixed production costs being allocated on kWh sales.

153. In OTP's last rate case, Enbridge and the MCC advocated that OTP be required to use an E8760 allocator for jurisdictional cost allocation purposes. The Commission declined to require this modification, finding it unlikely that such an allocator would be cost-justified and useful in the context of allocating costs between jurisdictions. It directed the Company to continue its investigation of this issue.[175]

154. In OTP's last rate case, the MCC advocated that OTP be required to use the breakeven methodology to allocate production plant costs in the CCOSS. The Commission declined to require this modification as well, concluding that the Company should continue to use the equivalent peaker method in its CCOSS.[176]

155. Finally, in OTP's last rate case, OES and the MCC recommended that OTP be required to develop an E8760 allocator in the CCOSS filed in its next rate case. Specifically, the OES recommended that an "E8760 allocator would more accurately reflect costs imposed by customer classes on OTP's system than the E1 or E2 allocation factors proposed by OTP."[177] The Commission agreed and required OTP to use the E8760 allocator in the CCOSS filed in its next rate case.[178]

B. JCOSS.

156. The jurisdictional allocators selected for OTP are particularly important, because its sales are spread substantially between jurisdictions. In 2009, OTP made 50.2 percent of its sales in Minnesota, 40 percent of its sales in North Dakota, and 9.7 percent in South Dakota.[179]

157. The equivalent peaker method is premised on the conclusion that utilities build generation to meet both energy needs and demand needs. Baseload plants are designed to meet base demand and energy year round. Peaking plants are designed to meet peak demand and energy needs. Base load plant costs more to build on a kW basis, but less to operate than a peaking facility. The equivalent peaker method allocates fixed generation costs, up to the cost of a peaking unit, on the basis of demand (D1), while fixed costs in excess of a peaking unit are allocated on the basis of energy (E1 and E2). This method results in approximately 76.5 percent of OTP's fixed generation costs being allocated on the basis of energy, and 23.5 percent are allocated on the basis of peak demand.[180]

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[175] *Docket 07-1178* Order at 22.
[176] *Id*. at 68-70.
[177] *Docket 07-1178*, Ex. 120, Rebuttal Testimony of Samir Ouanes at 7 (Feb. 29, 2008).
[178] *Docket 07-1178* Order at 65-66.
[179] Ex. 55, Erickson Surrebuttal at 19.
[180] Ex. 57, Schedin Direct at 13.

158. In this rate case, Enbridge and the MCC advocate allocating all fixed production costs in the JCOSS based on demand using the fixed variable method of allocation.[181] MCC argues that the equivalent peaker method penalizes jurisdictions with relatively higher load factors and off-peak energy usage. Because Minnesota ratepayers have a higher load factor, they pay proportionally more. MCC and Enbridge point out that several other utilities, including Xcel Energy, Minnesota Power, and Alliant, use a fixed-variable method for allocating production plant costs in the JCOSS. For OTP, this recommendation would involve replacing the E1 energy allocator with the D1 demand allocator. The result of this shift would reduce the Minnesota revenue requirement by approximately $1.6 million.[182]

159. OTP noted that the Commission, the NDPSC and the SDPUC have each approved identical jurisdictional allocators. This allows OTP to recover its cost of providing service without risk of over- or under-recovering its revenue requirement. Because those jurisdictions use the equivalent peaker method, OTP would be jeopardy of under-recovering the costs that a fixed variable method would shift to those jurisdictions.

160. OTP also argues that the equivalent peaker method appropriately recognizes the different levels of energy and demand requirements in the three states in which it provides service. If Minnesota ratepayers have a higher load factor, there is nothing unfair about allocating proportionally more costs than other states.

161. It also points out that the equivalent peaker method would not produce significantly different results for those other utilities, because they operate predominantly in one state and there is no issue of disparate demand/energy characteristics between jurisdictions. For example, Xcel Energy has less than 7 percent of its load in North Dakota and even less load in South Dakota. Minnesota Power operates only in Minnesota. Interstate Power and Light has less than 7 percent of its load in Minnesota, with 93 percent of its load in Iowa. For those three utilities, reflecting energy and demand differences in their jurisdictions would have little effect on jurisdictional costs.[183]

162. Furthermore, if the demand and energy is proportionate in each of their jurisdictions, using a fixed and variable methodology would not move costs between the jurisdictions. Thus, the additional burden of conducting the more complex equivalent peaker analysis would not necessarily be justified for those utilities.[184]

163. MCC acknowledged that OTP's other jurisdictions are likely to be reluctant to change, due to the increased costs for their ratepayers and the precedent of using the equivalent peaker method to date.[185] Enbridge argues that "[c]hanging conditions

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[181] Ex. 55, Erickson Surrebuttal at 17. The MCC and Enbridge do not challenge the use of the equivalent peaker method in the CCOSS, but they advocate a change in the allocator.
[182] Ex. 57, Schedin Direct at 14; Ex. 55, Erickson Surrebuttal at 17-18.
[183] Tr. 1:199, Beithon.
[184] Tr. 1:199-200, Beithon.
[185] Ex. 57, Schedin Direct at 15.

will also at times require changes in jurisdictional allocations." It maintains it has no intent to deny OTP the opportunity to earn its authorized return, but says that "some short-term inconsistency" until all jurisdictions adopt consistent jurisdictional allocation procedures is a small price to pay.[186]

164. Right now there is no inconsistency between jurisdictions. The Commission has expressly recognized the importance of using consistent jurisdictional allocation processes between the jurisdictions in which a multi-state utility does business.[187] The Administrative Law Judge accordingly recommends that the Commission accept OTP's JCOSS without requiring use of the fixed variable method.

165. If the Commission elects to retain use of the equivalent peaker methodology in OTP's JCOSS, then the MCC again proposes using the E8760 allocator instead of the E-1 (kWh) allocator to allocate fixed production – energy required costs in the JCOSS.[188]

166. OTP again opposes the use of an E8760 allocator in the JCOSS. It has not developed such an allocator, and the Commission did not require it to do so in the last rate case. As the Commission pointed out, development of the allocator for use on a system-wide, interstate basis would be very costly, and it was unclear whether the benefits of having an inter-jurisdictional E8760 allocator would exceed the costs of developing it.[189]

167. The Commission clearly rejected this proposal in OTP's last rate case, and the MCC has not provided any new arguments or evidence in this case to suggest a different result. The Administrative Law Judge recommends that Commission again reject the proposal to use the E8760 allocator in the JCOSS.

B. E8760 Allocator in the CCOSS.

168. OTP did develop and use an E8760 allocator for use in the CCOSS, in place of the E2 allocator. It continued, however, to use the E1 allocator for fixed production costs-energy required. It argues that Commission intended the use of the E8760 allocator to be used only with respect to costs that vary based on time of use and not for fixed production costs. It further argues that there was never a discussion in *Docket 07-1178* of using an E8760 variable fuel cost allocator to allocate fixed production costs, and that the use of the E8760 in place of the E1 allocator effectively converts the equivalent peaker method into the break-even methodology.

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[186] Ex. 55, Erickson Surrebuttal at 19.
[187] *In the Matter of the Petition of Northern States Power Company for Authority to Change its Schedule of Rates for Electric Utility Service for Customers Within the State of Minnesota*, Docket No. E-002/GR-85-558, Findings of Fact, Conclusions of Law, and Order at 23 (June 2, 1986); *In the Matter of the Application of Northern States Power Company for Authority to Increase Its Rates*, Order After Reconsideration (October 20, 1988); *In the Matter of the Petition of Northern States Power Company for Authority to Change its Schedule of Rates*, 416 N.W.2d 719, 728 (Minn. 1987).
[188] Ex. 57, Schedin Direct at 15; Ex. 58, Schedin Surrebuttal at 4.
[189] *Docket 07-1178* Order at 22.

169. OES also contended that OTP should have replaced both the E1 and E2 allocators in the CCOSS with the E8760 allocator. The MCC and Enbridge agree that OTP should have used the E8760 allocator in lieu of the D1 allocator in the CCOSS.

170. The OAG opposes using an E8760 allocator in the CCOSS because the OAG does not believe it reflects marginal energy costs. It also opposes the use of the E8760 allocator to allocate costs for fuel, purchased power, and the assignment of costs through the fuel clause adjustment.[190]

171. Contrary to OTP's arguments, the Administrative Law Judge concludes that the Commission resolved these issues in the last rate case. The Commission declined to require use of the E8760 allocator in the JCOSS, but it agreed with the OES that the E8760 should be used in place of the E1 and E2 allocators in the CCOSS.

172. OES requested that the Company re-run its CCOSS using the E8760 allocator instead of the E1 allocator and correcting two other errors with which the Company agreed (customer factors and removing the revenues and costs of the TailWinds program).[191] The Administrative Law Judge recommends that the Commission require OTP to use the CCOSS as revised by OES.

C. Use of E8760 in the FCA Rider.

173. OTP initially proposed to use the E8760 allocator for the base cost of energy, while allocating the current monthly automatic adjustments on an unweighted kWh basis. The OES recommended that, if the Commission approves the use of the E8760 allocator to the base cost of energy, the Commission should also require OTP to use the E8760 allocator in the Fuel Clause Adjustment (FCA). OTP did not object to this approach, because the OES, the Chamber, and Enbridge all advocated it. OTP performed the necessary analysis of impacts on the current customer class structure and provided it for the Commission's consideration.[192]

D. Updating Plant Cost in the CCOSS.

174. OES suggested that in its next CCOSS, OTP use the most recently available representative plant cost in conducting its study. Specifically, OES recommended using the original plant cost brought forward to a current cost using the Handy Whitman Index. OTP agreed to provide a CCOSS in its next rate case using that methodology.[193]

175. In surrebuttal testimony, MCC asserted that the cost of the peaker used in the equivalent peaker study should be the projected cost of the peaker proposed for use by OTP at the Solway Peaking plant, as identified in OTP's currently pending Integrated Resource Plan (IRP) proceeding. In that docket, OTP proposed using a cost of

[190] Ex. 67, Smith Surrebuttal at 69-75.
[191] Ex. 80, Ouanes Surrebuttal at 8-10 & SO-S-5; *see also* Finding Nos. 449 and 495.
[192] Ex. 77, Ouanes Direct at 19 & Attachment SO-32, page 4 of 5.
[193] *See* OTP Proposed Findings at ¶ 195.

$1,000/kW, including transmission, for the 2014 capital cost of a simple cycle aeroderivative and heavy-duty natural gas-fired combustion turbine.[194] It is not clear whether MCC proposed this change for the current CCOSS, or whether it suggests this change for a future CCOSS.

176. It appears that OTP used more than one peaker cost in the IRP Strategist model. It used the Solway peaker cost for an "aeroderivative heavy-duty" peaker and a GE Frame peaker for the cost of a more generic natural gas combined cycle turbine. OTP asserts that this more generic model was the same GE Frame peaker used in its CCOSS and that this particular peaker is the industry standard. When transmission costs are removed from the Solway peaker referenced in the IRP docket, the cost is about $927.[195]

177. The discussion of this issue is hindered by the fact that MCC did not raise it until surrebuttal. The Administrative Law Judge concludes, however, that it would be inappropriate to use 2014 peaker costs in the CCOSS without also updating the cost of base load plant.[196]

178. The Administrative Law Judge recommends that no changes be made to the peaker cost used for the CCOSS in this proceeding. The recommendation by OES to use a price escalator in the next CCOSS, which OTP has agreed to do, is sufficient to ensure that the next CCOSS uses current cost figures for both peaker and baseload plant.

E. Refinement of the Embedded CCOSS.

179. In its last rate case, OTP filed a marginal cost study to assist in designing rates. Enbridge requested that OTP be required to file an embedded cost study, to use as a test against the marginal cost study. The Commission agreed and directed OTP to file both a marginal and embedded CCOSS in its next rate case.[197]

180. In this case, OTP filed both marginal and embedded cost studies. The embedded cost study provided a break out of cost by demand, energy, and customer cost for each customer class.[198] Enbridge contends OTP failed to comply with the Commission's direction to provide an embedded CCOSS that provides sufficient unit cost information by function and rate class. Enbridge proposes that the Commission require OTP to file a JCCOS and CCOSS in its next rate case that would classify costs by function (high voltage transmission, low voltage transmission, primary distribution, secondary distribution, metering, etc.) and by unit cost (customer, kW, and kWh). In

[194] Ex. 58, Schedin Surrebuttal at 6 & LSS Attachment 2.
[195] Ex. 5, Workpapers page 357; *In the Matter of Otter Tail Power Company's 2011-2025 Resource Plan*, Docket E-017/RP-10-623, Application Attachment F, Section 2, Table 2, Mid cost; Ex. 58, Schedin Surrebuttal at LSS Attachment 2; Tr. 1:127-28, 170-72, Beithon.
[196] *In the Matter of the Application by Northern States Power Company, a Minnesota corporation for an Increase in Retail Electric Rates in Minnesota*, Docket No. E002/GR-08-1065, Order (October 23, 2009) at 44.
[197] *Docket 1178 Order* at 79.
[198] Tr. 1: 206, 207; Ex. 4, Vol. 3, Schedule E-3B.

addition, it asserts OTP should not include firm and non-firm sales in the same rate class so that unit cost information is on a firm service only basis.[199]

181. OTP objects to this proposal, contending that unbundled cost of service studies have not been done since the 1990s, when it was unclear whether states would have jurisdiction over transmission, and that such a study would only be used to support future arguments about stratification of transmission in lieu of using rolled-in rates.[200]

182. If the Commission is interested in further exploring stratification of transmission rates, it could require OTP to provide such a study. Otherwise, a component embedded cost study (like the one filed in this case) is appropriate if the purpose is to provide a comparison to a marginal cost study.

V. 2009 SALES AND REVENUES.

183. OTP's test-year sales are based on calendarized and weather-normalized 2009 historic sales, which correspond to the 2009 historic test year used in this case. In the Company's last rate case, OES calculated a retail revenue figure that was very close to OTP's calculation, and the Company agreed to use the OES figures.[201] OTP used essentially the same method to develop test-year sales and revenues in this case.[202]

184. OTP's first step in developing its test-year sales is to convert billing month sales data to calendar month data.[203] OTP uses two data sets in connection with calendarization of its billing month data: (i) the data set accumulated at the rate group level (known as CIS339); and (ii) the data set accumulated at the customer specific level (known as CIS/A). This step, known as "calendarization," adjusts for the differences between the various monthly billing cycles used for customers. Calendar-month revenue includes billed sales as well as an estimate of unbilled revenues. For 2009, the estimate of unbilled revenue increased retail revenues by just under $500,000.[204]

185. The second step involves converting the calendarized data to reflect normal weather rather than the actual weather that occurred in 2009 (referred to as "weather normalization").[205] OTP weather-normalizes by using an equation that adjusts the actual calendar-month sales for the difference between actual calendar-month weather conditions and normal calendar-month weather conditions, both of which are measured in terms of Cooling Degree Days and Heating Degree Days.[206] OTP's weather normalization process involves 20 years of OTP hourly weather data and

[199] Ex. 52, Erickson Direct at 22-23.
[200] Ex. 36, Beithon Rebuttal at 40-41.
[201] *Docket 07-1178*, Ex. 104, efiled as 5099384, and Heinen Opening Statement Exhibit, efiled as 5102204. The agreed-upon retail revenue figure was $131,389,408 in the last case.
[202] Tr. 1:126, Beithon.
[203] Ex. 23, Hansen Rebuttal at 4.
[204] Ex. 34, Beithon Direct at 17-18.
[205] Ex. 23, Hansen Rebuttal at 5.
[206] *Id*. at 9.

monthly kWh data. A statistical regression procedure is used to determine weather normalization models for each of OTP's rate groups.

186. Weather-normalized sales (kWh) are developed for each rate class, and then the sales numbers are priced for each rate code at current rates to determine revenues.[207]

187. OTP's weather normalization resulted in the addition of $272,629 in revenues.[208] The Company then adjusted fuel expenses based on its weather-normalization adjustment, which resulted in a decrease in expenses of approximately $35,506. The total test-year weather-normalized revenue amount is $132,806,609 based on forecasted sales of 2,141,125,599 kWh.[209]

188. OES agreed with the raw regression data used in OTP's sales analysis and with the weather-normalization process the Company used.[210]

189. OES proposed, however, that the Commission use test-year sales figures based on 2010 actual information where available and 2010 forecasted information where it was not available (as opposed to the 2009 data used by the Company), which was then weather-normalized using OTP's method.[211] The OES proposal resulted in revenue of $135,079,570 based on forecasted sales of 2,175,480,604 kWh. When the OES adjusts the revenue number for base cost of energy, the total adjustment is an increase to test-year revenue of $1,481,526.[212]

190. OES justified its decision to use 2010 sales data on the fact that OTP made some adjustments to 2009 data in other expense areas, for known and measureable changes in normalized plant in service, wage increases; medical and dental; FAS 112 postemployment; FAS 106 postretirement; FAS 87 pension; vegetation management, and purchased capacity.[213]

191. OES also criticized the use of separate data streams in the sales and revenue forecast, with CIS339 data used to develop sales figures and CIS/A data used to develop revenue figures. It contends that use of multiple data streams may lead to errors, may create irregular data patterns, and may create unreliable or unstable results. When OES attempted to convert OTP's Rate Class data into Rate Code data using OTP's method, OES calculated 2009 revenues that were approximately $374,825 greater than the Company's result.[214]

192. OES recommended that the Commission require the Company, in its next rate case, (1) to provide in its initial filing a summary spreadsheet that links together

[207] Ex. 34, Beithon Direct at 19.
[208] *Id*. at 18.
[209] *Id*. at 18-19 &PJB-1; Ex. 23, Hansen Rebuttal at 18.
[210] Ex. 84, Heinen Direct at 6-7.
[211] *Id*. at 15.
[212] *Id*. at 24.
[213] *Id*. at 8-9.
[214] *Id*. at 26.

test-year sales and revenue estimates, its CCOSS, its rate design schedules, income statement, and any other relevant rate case component; to provide a spreadsheet that fully links together all raw data in a format that enables the full replication of its process for calculating test-year sales and revenue; a spreadsheet that fully links its sales data from the most detailed level to the E schedule; and to file all data used for test-year sales and revenues at least 30 days in advance of its next general rate case filing.[215] OES also recommended that the Company be required, before its next rate case, to use the same raw input data in both test-year sales calculations and the E Schedules that calculate test-year revenue; to fully audit its SAS code and make any necessary changes to remove redundant steps and reduce overall complexity; and to work with OES during this audit to create a more streamlined test-year sales and revenue analysis.[216]

193. In response, OTP contends that its use of known and measurable changes to relatively few expenses in the 2009 test year does not justify the use of a 2010 sales forecast. It argues that the use of known and measureable changes is a recognized and routine part of using a historic test year and does not change a historic test year into a projected test year. In addition, it contends that none of the known and measureable changes it proposed would have any significant impacts on sales.[217]

194. For example, the adjustment to Plant in Service for projects brought on line in 2010 was for the installation of a substation and a new capacitor bank at a generating plant. The 2010 Plant in Service adjustments added approximately $1.8 million to OTP's plant in service (in comparison to total plant in service of $487 million).[218]

195. In addition, OTP adjusted seven expense categories for 2010 known and measureable changes. Adjustments for employee compensation and benefits, postemployment benefits, postretirement benefits, pension costs, vegetative maintenance, and storm damage increased expenses by approximately $3.43 million.[219] Other adjustments for known and measureable changes in 2010 decreased expenses by about $623,000 (by $232,430 for KPA Incentives, by $321,552 for purchased capacity, and by $68,815 for MISO congestion and losses).[220] The net increase for these expense adjustments was about $2.8 million, a small portion of OTP's total Minnesota jurisdictional expenses of $122 million.[221] It represents, however, about one-fourth of the claimed deficiency in this case.

[215] Ex. 84, Heinen Direct at 32-34.
[216] *Id*. at 28.
[217] Ex. 36, Beithon Rebuttal at 6.
[218] Ex. 5, Workpapers Vol. 4A at 83 & 85. OES did not object to these adjustments. *See* Ex. 96, La Plante Direct at 4-5; Ex. 97, La Plante Surrebuttal at 3.
[219] Ex. 4, Vol. 3, Schedule C-7, pages 1-3, line 14 (Labor, Employee Benefits, FAS 112, FAS 106, FAS 87, Veg. Maintenance, Storm Damages).
[220] *Id*., line 14 (KPA Incentive, Purchased Capacity, MISO Congestion and Losses).
[221] *Id*., line 14 (2009 Base Data).

196. In addition, OTP contends that the OES made numerous errors in calendarizing and weather-normalizing 2010 actual sales data and in calculating growth rates to forecast future sales. OTP's corrections to the OES calculations result in weather-normalized calendar-month sales for January through July 2010 of 1,265,497,925 kWh (as compared to the OES figure of 1,288,821,102 kWh for the same period).[222] It contends that weather-normalized, not actual sales, should be used to forecast growth. When all the calculation errors are corrected in the OES 2010 test year, total sales are 2,146,176,679 kWh.[223] It also argues that if a 2010 sales forecast is used, it must be adjusted for the known losses associated with 2010 sales reductions by a large customer.[224] Using weather-normalized historical sales for the period from October 2009 through September 2010 results in total sales of 2,140,884,462 kWh, without including any adjustment for the loss of the large customer.[225]

197. With regard to the use of two data streams, OTP responded that the only difference between the two data sets is that one adjusts billing corrections in the month affected by the correction, whereas the other reflects data in the month the correction is booked. It maintains that the net amount for the year should be the same for both data sets, but the months that are corrected would be different.[226] The Company agreed that in the future it could use one data set, rather than two, to avoid the issues identified by OES.[227] It had no specific response to the increased revenues in the amount of $374,825 calculated by OES.

198. In surrebuttal, the OES presented an updated forecast using updated 2010 sales and weather data, and adjusting for the loss of the large customer's sales. The forecasted revenue amount is $133,805,572 based on forecasted sales of 2,143,287,862 kWh. This is a difference of $999,363 from OTP's sales and revenue forecast.[228] OES also questioned OTP's unbilled revenue calculation for the first time, arguing the Company failed to provide sufficient information to allow the data to be verified. OES believes the Company was attempting to respond to the requests, but had difficulty doing so because the analyst who designed the system is no longer with the Company.[229] Because this critique of the unbilled revenue calculation was provided in surrebuttal, there is no response from OTP in the record.

199. OTP agreed to work closely with the OES following this rate case to maintain accuracy, improve efficiency, and reduce complexity in its future test-year forecasts. OTP also agreed to the OES recommendation that OTP provide the sales materials 30 days prior to filing a subsequent general rate case, if it uses a projected (but not historic) test year.[230] OTP confirmed its willingness to make substantial

[222] Ex. 23, Hansen Rebuttal at 9-11.
[223] Id. at 18.
[224] Ex. 36, Beithon Rebuttal at 6-9.
[225] *Id*. at 9.
[226] Id. at 10.
[227] Tr. 1:184, Beithon.
[228] Ex. 92, Heinen Surrebuttal at 26-29.
[229] *Id*. at 10-12.
[230] Ex. 36, Beithon Rebuttal at 9.

modifications to its current systems in order to reach an approach that is mutually acceptable to the OES and OTP for future rate cases.

200. The Administrative Law Judge concludes that the known and measurable changes OTP made to its 2009 test year expenses do not support the use of a 2010 sales level, as advocated by OES. None of these adjustments appear to have any impact on sales. It would be more appropriate to examine the propriety of each proposed known and measureable change to the expense in question for a 2009 test year, than to categorically increase the sales forecast to 2010 levels, without an increase in all O&M expense categories.[231] The OES approach is inconsistent with the concept of an historical test year and would result in a fundamental mismatch between sales revenues and expenses.

201. Although OES appropriately questioned the complexity of the process used by OTP, and had concerns about the use of different streams of data and the calculation of unbilled revenue, it agreed with the basic approach taken by the Company and used that same approach in its own analysis of 2010 expenses. The primary dispute was whether to use 2009 historical data or 2010 historical and projected data. The Administrative Law Judge concludes that the Company, with one exception, has demonstrated the reasonableness of its sales and revenue numbers for 2009. The OES has established that the 2009 revenue numbers should be increased by $374,825, based on its revenue calculation that attempts to reconcile the use of different data streams for sales and revenues.[232] The Administrative Law Judge accordingly recommends that the Commission use OTP's 2009 test year revenue number of $132,806,609, adjusted by $374,825. The resulting total test-year weather-normalized revenue amount is $133,181,434. In its compliance filing, the Company should clarify the process for its unbilled revenue calculation and correct the figure, if necessary, after consultation with OES.

202. The Administrative Law Judge also recommends that the Commission require the Company (1) to provide the materials requested by OES in the Company's initial filing in its next rate case and (2) to file all data for its test-year sales and revenues at least 30 days in advance of its next general rate case filing. The difficulty OES had in evaluating the impacts of using two separate data streams to produce sales and revenue numbers provides a more than sufficient basis for such a requirement. It is in the Company's interest to make its process for setting test-year sales and revenues as accessible as possible in order to minimize the time and expense involved in verifying the accuracy of these numbers and to potentially eliminate or narrow future disputes.

[231] OTP has seen an average increase in non-fuel O&M expenses of three percent annually over the last five years. If the test year O&M expense were similarly increased by three percent, OTP's revenue requirement would increase by approximately $1.6 million beyond the known and measureable changes that were made.
[232] Ex. 84, Heinen Direct at 26.

VI. PENSION AND BENEFITS ISSUES.

A. Pension Expense.

203. OTP has a defined benefit pension plan that requires no direct contributions from employees. The plan covers the majority of the employees of the electric utility. Non-union electric utility employees hired after September 1, 2006, are not eligible for the defined benefit plan but are eligible for a defined contribution plan. In addition, the union contract negotiated in 2008 provides that new hires after December 31, 2008, are not eligible for the pension plan.

204. At the outset, the Administrative Law Judge notes that analysis of these benefits has been complicated by the manner in which the Company has presented the information. It would be useful if the Company consistently separated out expenses for each benefit, instead of combining them, and made it clear whether amounts described in testimony are a total company or Minnesota jurisdictional expense.

205. In its initial filing, the Company provided actual pension costs (Minnesota jurisdiction) for 2006-2009, and its projected pension costs for 2010, as follows:

2006 $2,677,546
2007 $2,078,169
2008 $1,326,491
2009 $1,445,383
2010 $3,213,055[233]

206. The estimate of 2010 expense was based on the use of a 5.75 percent discount rate.[234]

207. The Company also maintains that pension expenses are expected to increase in the period from 2011 to 2015.[235] The assumptions used to support this projection are not in the record.

208. OES initially objected to the use of 2010 expense, because OTP had used a 2009 test year adjusted for an actuarially forecasted "known and measurable change" for 2010 that required more scrutiny than the use of historical data. OES did not, however, recommend disregarding 2010 expense data; it treated the proposed 2010 costs as a forecasted 2010 expense. OES concluded the 2010 amounts were both too large to include in rates and overstated because of the use of a low discount rate.[236] OES asserted the expense was too large based on the amount of the increase from

[233] Ex. 98, Campbell Direct at 47.
[234] Ex. 15, Brause Rebuttal at 42.
[235] Ex. 29, Wasberg Rebuttal at 7.
[236] Ex. 98, Campbell Direct at 34-38.

2009 and questioned the assumption that ratepayers should be required to pay for 100 percent of employee pension expense, with the exception of recent hires.[237]

209. Based on all the above reasons, OES proposed that pension expense for 2006 through 2010 be averaged and that $2,148,128 be included in the test year.[238]

210. The MCC did not propose any specific level of adjustment but recommended that OTP reduce its defined benefit pension commitments to employees as many other private-sector employers are doing.[239]

211. The OAG proposed using actual 2009 expense for the test year.[240] It argued that OTP has over-recovered pension expense set in the last case. This argument is factually incorrect. In the last rate case, the Commission allowed pension costs in the amount of $4,232,101 on a total company basis, or about $2.1 million for the Minnesota jurisdiction.[241] Those rates were implemented in 2009. It does not appear that there was any over-recovery of this expense in 2009-2010.

212. In rebuttal, OTP updated its 2010 pension expense to reflect actual 2010 expense. The updated costs decreased the 2010 Minnesota jurisdictional amount for pension expenses by $409,026, for a resulting total of $2,804,029.[242] The Company's actuary used a discount rate of 6 percent to calculate this expense.[243]

213. OES again recommended using a five-year average and incorporating OTP's actual 2010 pension expense, which results in test year expense of $2,051,648, or $752,381 less than the Company's revised 2010 test-year amount of $2,804,029.[244]

214. OTP contends that averaging will understate its expense for the time in which rates are in effect. It argues that its actual expense levels are the most accurate cost figure in the record.

215. In the past, the Commission has sometimes used actuarially determined costs and has sometimes used averages, rejecting categorical insistence on any single methodology. Its choice has always been tied to the specific facts of each case. In OTP's 2007 rate case, for example, the Commission found the use of actuarial determinations to be most accurate; in Minnesota Power's last rate case, the

[237] Ex. 98, Campbell Direct at 44-45.
[238] *Id*. at 50-51.
[239] Ex. 58, Schedin Surrebuttal at 8-10.
[240] Ex. 59, Smith Direct at 40.
[241] *Docket 07-1178*, ALJ Findings of Fact, Conclusions of Law and Recommendation at ¶ 256 (June 17, 2008).
[242] Ex. 36, Beithon Rebuttal at 51.
[243] Ex. 29, Wasberg Rebuttal at PEW-2, Schedule 2; Ex. 15, Brause Rebuttal at 42.
[244] Ex. 104, Campbell Revised Surrebuttal at 27-38.

Commission chose to use an averaging approach based on part on the use of a volatile pension discount rate at a single point in time.[245]

216. OTP's discount rate is set by a committee, subject to limitations imposed by its actuary and auditor.[246] The discount rates used for actuarial determinations are based on: (i) the yields of debt securities with ratings of "Aa" or higher from recognized rating agencies; and (ii) yield curve and bond matching models that are matched to the OTP benefit plans that are being valued. OTP's discount rate has been fairly stable over the past five years, varying from a low of 5.75 percent in 2006 to a high of 6.7 percent in 2009. The average discount rate over the past five years is 6.175 percent.[247]

217. Even assuming that this discount rate is set more reasonably than the one in the Minnesota Power case, however, the record reflects that pension expense declined by approximately $1 million between the time of the Company's initial filing in April 2010 and the filing of rebuttal testimony in October 2010, and that the decline was due primarily to a change in the discount rate from 5.75 percent to 6.00 percent. As OES points out, changes in assumptions, timing of updates, status of the financial market, and many other factors can contribute to large changes in pension expense in a relatively short period of time.

218. The Administrative Law Judge agrees that this degree of volatility makes predicting pension expense difficult. The OES proposal to use the five-year average expense is essentially a compromise that reflects both the trend toward increasing actual expense levels and the difficulty of predicting future expense. The OES proposal takes into account the necessity that rates be reasonable from the perspective of ratepayers. The Administrative Law Judge recommends that pension expense be set as recommended by OES.

B. Other Post-Retirement Employee Benefits/OPEB.

219. The Company's OPEB costs include retiree medical expense and life insurance.[248] Retiree medical is available for regular status employees, enrolled in an OTP Health Plan, who are 55 or older at retirement and have 10 or more years of service after they are 45 years old.[249] Retirees pay significant premiums for the retiree healthcare plan. For example, a retiree pays $674 per month to cover the retiree and

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[245] *In the Matter of the Application of Minnesota Power to Increase Electric Rates,* Docket No. E-015/GR-09-1151, Findings of Fact, Conclusions and Order at 26 (*Minnesota Power*).
[246] Ex. 15, Brause Rebuttal at 36.
[247] *Id.* at 45.
[248] Ex. 98, Campbell Direct at 54-55; Ex. 100 at NAC-19, OES IR 167. OES appears to assume based on OTP's description of ESSRP as a "post-retirement benefit" that ESSRP expenses are also included in FAS 106; the Administrative Law Judge believes ESSRP expenses are not included in that account, but are included in some other compensation category. Accordingly, this discussion of OPEB benefits assumes that ESSRP expense is not included. *See* Finding Nos. 150-55 pertaining to ESSRP expense.
[249] Ex. 100 at NAC-19.

spouse.[250] Non-union employees hired after September 1, 2006, and Coyote Union employees hired on or after January 1, 2009, are not eligible for retiree medical.[251]

220. The Company pays for up to $50,000 of life insurance for employees with 25 or more years of service as of January 1, 2003, with the value of the life insurance diminishing as employees get older. Employees with less than 25 years of service as of January 1, 2003, pay full cost at the contract rate for life insurance at the time of their retirement.[252]

221. The Company's actual OPEB costs for the Minnesota jurisdiction for 2006 to 2009, and its estimated 2010 expense, were as follows:

2006	$1,540,375
2007	$1,442,770
2008	$1,650,840
2009	$1,714,557
2010	$2,073,743[253]

222. The basis for the 2009-2010 increase includes assumptions by Mercer Health of a 9.4 percent increase in active medical expenditures, which includes a medical trend rate of 8.5 percent and an additional increase of almost 1 percent to cover requirements in the Patient Protection and Affordable Care Act.[254]

223. OES initially objected to use of a 2010 estimate in lieu of 2009 actual expenses, as it did for pension expense. It also concluded, however, that OPEB costs have not been as volatile as pension costs.[255] OES did not recommend use of 2009 expense numbers, but instead recommended that the 2009 test year amount be increased by 3.64 percent, based on the average percent increase in actual costs from 2006 to 2009. The resulting number was $1,776,889.[256]

224. In rebuttal, OTP updated its estimated 2010 OPEB expense to actual expense. The updated costs increased the 2010 Minnesota jurisdictional amount for OPEB by $92,941, to $1,849,407.[257]

225. In response, OES updated its average year-to-year increase to 9.11 percent. Applying that increased percentage to 2009 expenses, OES adjusted its recommended allowable Minnesota jurisdictional OPEB expense to $1,870,857.[258]

[250] Ex. 100 at NAC-20, OES IR 169.
[251] Ex. 100 at NAC-19.
[252] *Id.*
[253] Ex. 98, Campbell Direct at 59.
[254] Ex. 29, Wasberg Rebuttal at 14.
[255] Ex. 98, Campbell Direct at 58.
[256] *Id*. at 60.
[257] Ex. 36, Bethon Rebuttal at 51.
[258] Ex. 104, Campbell Surrebuttal at 40.

226. The difference between the final OES recommendation and the final OTP proposal for OPEB expenses is $21,450.

227. While the increase in OPEB expense from 2009 to 2010 is large, the Administrative Law Judge concludes there is no evidentiary basis to reject it. These are reasonable plans, and they require significant contributions by employees. The methodology used by OES (based on average percent increases over the five-year time period) has no real theoretical foundation except that it slightly reduces the total amount of the expense.

228. The Administrative Law Judge accordingly recommends that the Commission accept the Company's proposed OPEB expense in the amount of $1,870,857.

VII. EMPLOYEE COMPENSATION ISSUES.

229. In Minnesota Power's recent rate case, the Commission provided guidance as to how employee compensation issues are to be evaluated:

> [T]here is no evidence in the record that total compensation levels for the Company's key management employees are excessive or inconsistent with industry norms. Nor, importantly, is there any evidence in the record that the incentives built into the compensation scheme are misaligned with ratepayer interests….
>
> Barring excessive compensation levels, skewed incentives, or other public policy concerns, the Company has the discretion to structure its compensation packages in accordance with its best business judgment.[259]

A. Long-Term Incentive Compensation.

230. OTP proposed to recover $88,972 for its long-term incentive compensation program.[260] The main components of OTP's long-term incentives are grants of restricted stock and stock options. Qualifying employees are awarded restricted stock units and options based on salary, job level, and the price of the stock at the date of the grant.[261] OTP maintains that long-term incentives are reasonable and encourage the retention of executives and key management employees.[262]

231. Both the OES and OAG opposed cost recovery for OTP's long-term incentive compensation program.[263]

[259] *Minnesota Power,* Findings of Fact, Conclusions of Law, and Order at 29.
[260] Ex. 29, Wasberg Rebuttal at 29-30.
[261] Ex. 26, Wasberg Direct at 8.
[262] Ex. 29, Wasberg Rebuttal at 30.
[263] Ex. 110, Lusti Direct at 21-24; Ex. 59, Smith Direct at 29-30.

232. The Commission typically does not allow utilities to recover long-term incentive compensation.[264] The Commission articulated its basis for denying recovery of long-term incentive compensation costs in its recent Minnesota Power Order:

> … as the Commission previously recognized, offering key decision makers large financial rewards for producing short term shareholder benefits does not promote regulatory efficiency or the long term fortunes of the Company. The Company concedes that with respect to the LTIP program, there is emphasis on earnings as a goal. Such a goal benefits shareholders more so than ratepayers. The Commission finds that these considerations justify the decision to eliminate the Long Term Incentive Plan in its entirety.[265]

233. OTP has similarly failed to show that its long-term incentive program is aligned with the interests of ratepayers and is reasonable. The ALJ accordingly recommends that the Commission should disallow recovery of long-term incentive compensation in this proceeding. This adjustment reduces expenses by $88,972.[266]

B. Management Incentive Compensation.

234. OTP's Management Incentive Plan is the incentive plan for the Company's 19 management employees.[267] The Management Incentive Plan is based on a range of metrics, including financial performance as well as individual criteria that vary by the job and responsibility.[268]

235. OTP's Management Incentive Plan test year expense is $589,038 on a total Company basis, or $290,867 for the Minnesota jurisdiction.[269] It was based on the actual expense for 2009, plus some carryover from 2008, adjusted to remove amounts over a 25 percent cap on individual employee incentives.[270]

236. The OES supports expense recovery for OTP's Management Incentive Compensation, but would limit recovery to a five-year average from 2005-2009. This approach would result in a downward adjustment of $92,784 to the claimed expense.[271]

237. The OAG recommends excluding Management Incentive Compensation expense entirely, based on its argument that the financial performance objectives in the plan only benefit investors.[272]

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[264] Ex. 110, Lusti Direct at 23.
[265] *Id*. at 23-24; *In the Matter of the Application of Minnesota Power*, Docket No. E-015/GR-08-415, Findings of Fact, Conclusions of Law, and Order at 44 (May 4, 2009).
[266] Ex. 110, Lusti Direct at 24; Ex. 111, Lusti Direct Attachments at DVL-7W at 1. *See also* Ex. 112, Lusti Revised Surrebuttal at 17 and DVL-7W at 1.
[267] Ex. 26, Wasberg Direct at 7.
[268] Ex. 29, Wasberg Rebuttal at 26; Ex. 59, Smith Direct at 31.
[269] Ex. 111 at DVL-15.
[270] Ex. 26, Wasberg Direct at 17.
[271] Ex. 110, Lusti Direct at 25-26; Ex. 111 at DVL-15.

238. Management Incentive Plan expenses on a total company basis during the five years in question (with any amounts over 25 percent of base pay removed) are as follows:[273]

Year	Incentive Amount
2005	$478,536
2006	$135,619
2007	$417,868
2008	$480,532
2009	$492,158

239. It is apparent that expenses in 2006 were markedly lower than those in other years. The OES five-year average thus includes what is clearly an atypical year. Use of a four-year average that excludes 2006 would result in a test year expense of $467,274 on a total company basis, or $230,496 for the Minnesota jurisdiction. This adjustment would decrease the originally proposed expense in the amount of $60,371.[274]

240. While expenses for the Management Incentive Plan have fluctuated over time, there is no evidence to explain why they fluctuate or how to best predict future expenses. Based on the record, however, the OES recommendation is unreasonable because the inclusion of 2006 distorts the Company's typical expense levels.[275] The OAG recommendation to exclude the expense entirely is also unreasonable, because this incentive program rewards more than financial performance and benefits ratepayers as well as shareholders.

241. The OES argues that, because it accepted the Company's proposed expense for Key Performance Awards (KPA), which were based on the average payout percentage for the years 2005-2009, the Company should be required to accept use of a straight five-year average for this expense.[276]

242. The Key Performance Awards are intended for the Company's 363 non-union, non-management employees. The maximum payout level is 6 percent of base salary, and the criteria for receiving an award include both operating criteria and financial criteria. The test year amount for this expense was based on the average percentage payout level (3 percent) over five years.[277]

243. The Administrative Law Judge can see no basis for requiring that the same averaging period be used for both KPA and management incentive expense. The

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272 Ex. 59, Smith Direct at 31-32.
273 Ex. 29, Wasberg Rebuttal at 25.
274 *Id*. at 25.
275 *Id*. at 24.
276 Ex. 112, Lusti Revised Surrebuttal at 19.
277 Ex. 26, Wasberg Direct at 6, 16, and 24.

point is to develop a reasonably representative amount for the expense in question. There was relatively little variability in the amount of management incentive expense except for in 2006; use of a straight five-year average does not result in a representative expense level for the 2005-2009 period. The actual payouts for KPA expense, in contrast, were much more variable over that period, and use of a straight five-year average for that expense is entirely justifiable.

244. The Administrative Law Judge recommends an allowance for Management Incentive plan expense of $467,274, which is the average expense from 2005-2009, excluding the atypical 2006 expense. This should amount to $230,496 for the Minnesota jurisdiction, or a decrease of $60,371 to the proposed expense.

245. The Administrative Law Judge also recommends that the Commission order OTP to retain the tracking and refund mechanism established in the last rate case so that amounts collected from ratepayers but not paid out in Management Incentive Compensation are credited to ratepayers.

C. Achievement Awards.

246. OTP proposed to recover test year expense of $147,202 (total company), or $74,000 for the Minnesota jurisdiction, for Achievement Awards.[278] Achievement Awards are provided to OTP employees who demonstrate exceptional performance involving extraordinary intensity, or integration or innovation on a specific project, assignment or workload that is in addition to their normal work responsibilities.[279]

247. The OES did not oppose recovery of the Achievement Awards expense. The OAG recommended excluding this expense on the basis that it does not benefit ratepayers.[280]

248. OTP provided evidence that Achievement Awards have been given to employees who receive no overtime compensation for additional hours worked during extended storm restoration, and for the successful implementation of a new system designed to benefit customers through improved load management.[281]

249. The Company has demonstrated that Achievement Awards are a small but important part of its employee compensation plan and that the awards benefit ratepayers by rewarding outstanding commitment and dedication by OTP employees. This expense is reasonable and appropriate, and the Administrative Law Judge recommends that this test year expense be allowed.

[278] Ex. 59, Smith Direct at 32; Ex. 60 at RLS-13 (OTP Public Response to OAG 206a), at 2.
[279] Ex. 29, Wasberg Rebuttal at 27-28.
[280] Ex. 59, Smith Direct at 32-33.
[281] Ex. 29, Wasberg Rebuttal at 27-28.

D. ESSRP Supplemental Pension Benefit.

250. The Executive Survivor & Supplemental Retirement Plan (ESSRP) is an unfunded, nonqualified defined benefit plan adopted in 1983 to provide key executives and management employees with benefits intended to protect against reductions in benefits due to tax law limitations. It was implemented as a supplement to the pension plan for higher income employees. Benefit calculations include income from incentive payments, which are excluded from calculation of the pension plan benefit. The plan provides benefit payments to these employees on their retirements for life, or to their beneficiaries on their deaths for 15 years post-retirement. The plan is frozen to employees who are not eligible for the pension plan due to their date of hire. OTP contends this plan is a reasonable part of its overall compensation and benefits package for key executives and management employees.[282]

251. OTP proposed to recover ESSRP expense of $684,220 (Minnesota jurisdiction).[283] In addition, $246,921 was included in the test year as an allocated corporate ESSRP expense, for a total of $931,141.[284]

252. The OAG recommended excluding OTP's ESSRP expenses.[285] Although it appears that supplemental pension benefits similar to ESSRP have been disallowed by other state commissions, recovery of these expenses has been permitted to date in Minnesota. It does not appear, however, that any party has challenged these expenses in the past, or even been aware that the Company had this plan, because OTP has not described this benefit separately in its past discussions of total compensation and benefits.[286]

253. OTP's annual report reflects that, as an unfunded plan, ESSRP has no assets, and contributions are equal to the benefits paid to plan participants. The Company expects ESSRP benefit payments to gradually increase over the period from 2010 to 2019.[287]

254. The OAG makes a persuasive argument that ratepayers should not be required to fund this benefit. OTP's executives are objectively well paid, regardless of industry standards, and the pension plan is generous. Although this is an expensive benefit, and it appears likely to remain expensive, there is no specific information in the record about how it is calculated or whether this type of benefit is consistent with industry norms. OTP argues only that its total compensation package is lower than industry norms.

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[282] Ex. 29, Wasberg Rebuttal at 30-31; Ex. 4, OTP 2009 Annual Report at page 79.
[283] Ex. 60, RLS-16 at 1.
[284] Ex. 60, RLS-16 at 2. For many of the former or current employees participating in this program, the amount of ESSRP expense far exceeds the amount of their pension expense. For one employee, the ESSRP expense was more than ten times the annual pension expense in 2009. *See* Ex. 60, RLS-16 at 3.
[285] Ex. 59, Smith Direct at 33-35.
[286] Tr. 1:117-18.
[287] Ex. 4, OTP 2009 Annual Report at 79.

255. The record is insufficient to conclude that this particular benefit is consistent with industry standards and aligned with ratepayer interests. The reasons that support exclusion of long-term incentive compensation from rates similarly support exclusion of this expense, since the benefit calculation includes some (unspecified) amounts of incentive compensation. Accordingly, the Administrative Law Judge concludes that OTP has failed to demonstrate the reasonableness of this expense and recommends that this expense be disallowed.

VIII. OTHER COST OF SERVICE ISSUES.

A. Rate Base Recognition of Customer Supplied Funds.

256. Financial Accounting Standard Number 87 is also known as "Employers Accounting for Pensions" or "FAS 87." Financial Accounting Standard Number 158 is also known as "Employers Accounting for Defined Benefit Pension and Other Postretirement Plans" or "FAS 158." FAS 158, which became effective at the end of 2006, is intended to recognize the underfunded balance in a pension account by taking out the delayed recognition of economic events, resulting in the establishment of a pension liability.[288] The pension liability recognizes that the underfunded pension balance may include contributions made to the pension plan in a given year that exceed the pension expense reflected in rates.[289] In other words, the prepaid expense is accounted for in determining the amount of the liability in FAS 158; the question here is whether prepayment of pension expense (by either ratepayers or OTP) should also be included in base rates.

257. In OTP's last rate case, which used a 2006 test year, OTP removed the prepaid pension expense balance related to FAS 87 on the assumption that the balance was eliminated because of the implementation of FAS 158.[290] In its initial filing in this case, OTP continued to assume that the prepaid expense should not be separately included.

258. In the OAG's direct testimony, it pointed out that OTP had not accounted for the difference between cash payments and expenses for FAS 87 that would result in either a reduction to rate base (if ratepayers paid more than the current expense) or an increase in rate base (if OTP paid more than the current expense). It indicated that NSP had agreed in its most recent gas rate case to continue to record in rate base the difference between its expense and actual payments for pensions and other post-employment benefits. The OAG requested that OTP provide testimony showing "what the total rate base impact would be for each year beginning when OTP adopted FASB 87, 106, and 112" in schedules similar to OTP's response to OAG 112a.[291]

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[288] Tr. 1:71 (Sem).
[289] *Id*.
[290] Ex. 25, Sem Rebuttal at 4.
[291] Ex. 59, Smith Direct at 94-95; Ex. 63, Attachment RLS-34. The terms of the NSP agreement are not in the record, and the issue is not discussed in the Commission's order.

259. In rebuttal, OTP agreed with the proposition that these timing differences should be reflected in rate base. It provided a schedule of the monthly balance of FAS 87 prepaid pension expense for 2009, which averaged $6,173,058. The Minnesota jurisdictional share of this expense is $2,934,879.[292]

260. OTP also made an adjustment to FAS 106, the accounting standard for other post-retirement benefits. The need for this adjustment was discovered while OTP was responding to a different OAG Information Request, which sought to determine why the November 2009 prepayment credit on Work Paper A-4 (Volume 4A, page 271 of the original filing) was approximately $4 million less than the October and December 2009 amounts.[293] OTP discovered that the accumulated provision for post-retirement benefits included in the revenue requirement calculation had been separated into four accounts instead of the two original accounts as shown in the work paper.[294] The balances in the two new subaccounts were inadvertently omitted from Workpaper A-4 during calculation of the 2009 actual and test year jurisdictional cost of service study.[295]

261. To correct this error, OTP proposed that the accumulated provision for post-retirement benefits in the rate base should be adjusted down by an additional $625,914 on a total company and $297,581 on a Minnesota jurisdictional basis.[296]

262. The combined effect of the two adjustments to FAS 87 prepaid pension expense and FAS 106 post-retirement benefits is an increase of total company prepayments in the amount of $5,547,144 and an increase of $2,637,298 on a Minnesota jurisdictional basis.[297]

263. The OES has taken no position on the propriety of these adjustments.

264. The OAG has taken the position that, because the Company did not provide the information it requested in its direct testimony, in the format requested in its direct testimony, OTP's proposed adjustment should be rejected.[298]

265. The OAG made its own calculation of prepaid pension expense, based on OTP's response to the OAG's Information Request 112a. This information request sought, for the period 2006-2009, the FAS 87 expense reported for financial reporting purposes; the expense reported for tax purposes; the expense reported for regulatory reporting purposes; the amount of cash payments; the amount recorded as a deferred asset or liability; the amount representing the difference between cash payments and the amount reported for financial reporting purposes; and the deferred taxes or credits for the difference. The OAG averaged the difference between cash payments and the amount reported for financial reporting purposes over that time period, the result of

[292] Ex. 25, Sem Rebuttal at 8.
[293] *Id*. at 5.
[294] *Id*.
[295] *Id*. at KS-2, Schedule 2, Attachments 1 and 2.
[296] *Id*. at 6.
[297] *Id*.
[298] Ex. 67, Smith Surrebuttal at 64.

which is $330,604. The OAG characterizes this amount as the average annual overpayment by ratepayers, and it multiplied that figure by 24 (to reflect the 24 years since adoption of FAS 87), resulting in a recommended $3.8 million decrease to rate base.[299]

266. The OAG also recommended rejection of OTP's proposed adjustment for other post-employment benefit expenses, believing it to be a proposed increase (rather than decrease) to rate base.[300]

267. The OAG's calculation of prepaid pension expense appears to be without adequate basis in the record. It does not appear that the data reflected in OTP's response to Information Request 112a includes any prepaid balances, whether in favor of the Company or the ratepayers. The Administrative Law Judge cannot conclude that the OAG's methodology is sound or recommend that its proposed adjustment be made.

268. It is also unclear to the Administrative Law Judge whether the prepaid expense should appropriately be included in rate base. It appears the removal of this expense in 2006 was more of a considered decision based on the implementation of FAS 158 than an "inadvertent error," which is how OTP described it in testimony. Based on the record as a whole, the Administrative Law Judge recommends that the Commission reject the Company's proposed rate base adjustment for prepaid pension expense at this time. If OTP's past treatment of these expenses was truly an inadvertent error, it can propose the change in its next rate case and give all parties an opportunity to fully examine the issue.

269. On the other hand, OTP's recommended adjustment for FAS 106 does appear to be the straightforward result of an inadvertent omission of two subaccounts, uncomplicated by the implementation of FAS 158. The Administrative Law Judge accordingly recommends that the Commission adjust the rate base downward by $297,581 for the Minnesota jurisdiction.

B. Unamortized Rate Case Expense.

270. OTP requested $495,079 in the test year to recover the uncollected balance of expenses from its last rate case, which the Commission ordered to be amortized for recovery over three years.[301] The rate case balance from the prior rate case will be fully amortized at the end of November 2010.[302] The Company has proposed that, to avoid over-collecting the unamortized balance that will be fully amortized in November 2010, OTP should be allowed to continue to recover the unamortized balance through November 2010, and that the expenses recovered in final rates should be reduced by $495,079.[303] This adjustment would be reflected as of December 2010 when calculating any interim rate refund. Alternatively, the $495,079 in

[299] Ex. 67, Smith Surrebuttal at 68.
[300] *Id*. at 66.
[301] Ex. 36, Beithon Rebuttal at 13.
[302] *Id*.
[303] Ex. 36, Beithon Rebuttal at 15.

expense could be amortized over the same three-year period the current rate case expenses will be amortized.[304]

271. The OES opposed recovery of the unamortized rate case expenses on the basis that there is no true-up mechanism for recovery of expenses between rate cases, and the Commission has denied recovery of unamortized expenses in other recent cases.[305]

272. The Administrative Law Judge recommends that the Commission deny recovery of OTP's unamortized rate case expenses. The mechanism adopted in the last rate case was intended to protect ratepayers from over-collection of this expense; it was not intended to abrogate the normal presumption that expenses do not carry over from one rate case to the next.

C. Costs of Making Charitable Contributions.

273. OTP included $19,500 of administrative costs for its employee time invested in running the charitable contributions program.[306] The OES recommends disallowance of these expenses.[307]

274. Charitable contributions made by a utility are a legitimate cost of doing business, and Minn. Stat. §216B.16, subd. 6, authorizes recovery of 50 percent of qualified charitable contributions. The Commission has disallowed, however, the administrative costs of making those contributions. In Xcel's 2008 electric rate case and its 2009 gas rate case, the Commission disallowed 100% of the costs of administering Xcel's charitable foundation, on the ground that shareholders derive goodwill from these contributions and it is appropriate for them to bear 100 percent of the cost of making them.[308]

275. OTP argues that its costs should be permitted because it does not have a separate foundation and is not seeking to recover costs of administering a separate entity. It argues that, in order to make charitable donations, it must dedicate resources, and those costs should be recoverable. In addition, OTP argues that it is inconsistent with Minn. Stat. § 216B.16, subd. 6, to allow recovery of 50 percent of donations, but disallow the administrative costs necessary to make the donations. In the alternative, OTP argues that it should be allowed to recover 50 percent of these costs.

276. The Administrative Law Judge recommends that the Commission exclude the $19,000 in costs identified by OES. The Commission has made a policy decision that ratepayers should not be responsible for the administrative costs of making those contributions. The Administrative Law Judge can see no reason why OTP's

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[304] Ex. 36, Beithon Rebuttal at 15.
[305] Ex. 97, La Plante Surrebuttal at 5.
[306] Ex. 36, Beithon Rebuttal at 16.
[307] Ex. 96, La Plante Direct at 10 and LL-10; Ex. 97, La Plante Surrebuttal at 8.
[308] *In the Matter of the Petition of Xcel Energy to Increase Electric Rates*, Docket No. E002/GR-08-1065; *In the Matter of the Petition of Xcel Energy to Increase Gas Rates*, Docket No. E002/GR-09-1153, Findings of Fact, Conclusions of Law, and Order at 15 (Dec. 6, 2010).

administrative costs should be treated differently than those of Xcel's nonprofit foundation.

D. Storm Damage Expense.

277. OTP proposed increasing its 2009 actual storm damage expense by $250,796, bringing this expense for the Minnesota jurisdiction to $570,703, its budgeted amount for 2010.[309] OTP's storm repair costs have been highly variable over the past five years:

	Total Company Actual	Minnesota Jurisdiction
2005	2,098,922	998,218
2006	304,478	144,805
2007	436,839	207,754
2008	942,833	448,398
2009	672,659	319,907
Average	891,126	423,807

278. Because of this variability and the consequent difficulty of predicting the future expense, OES recommended using the five-year average to smooth random weather effect. This approach reduces the proposed amount by $146,896, for a total expense of $423,807 for the Minnesota jurisdiction.[310] OTP accepted the OES adjustment.[311]

279. The OAG objects to this resolution and recommends setting test year storm damage expense at $400,687. The OAG calculated this amount by using a weighted average, which weights the combined experience of 2005, 2006, and 2007 at 25 percent, while weighting 2008 and 2009 at 75 percent.[312] The OAG argued that recent storm damage expenses are more representative because the Commission increased recoverable expenses for tree trimming and vegetation management in the last rate case.[313]

280. OTP acknowledged that tree trimming helps avoid storm damage; however, OTP argues that the OAG's proposal gives unfounded weight to recent experience, despite significant variability in this expense over the past five years.

281. The record evidence is insufficient to support the disproportionate weighting of the Company's experience in 2008 and 2009, as proposed by the OAG. Moreover, this method is inconsistent with the treatment of tree trimming and vegetation

[309] Ex. 34, Beithon Direct at 52; Ex. 110, Lusti Direct at 18.
[310] Ex. 112, Lusti Revised Surrebuttal at 23. The OES brief indicates that the total expense number should be $432,807; however, the Minnesota jurisdictional share of $891,126 is $423,807 [891,126 * 47.558623% = 423,807].
[311] Ex. 36, Beithon Rebuttal at 16.
[312] Ex. 59, Smith Direct at 45.
[313] Ex. 67, Smith Surrebuttal at 52.

management expense (see below), for which the OAG has recommended use of a straight five-year average.

282. The Administrative Law Judge recommends that the Company's storm damage expense should be recovered based on the agreement with OES, in the amount of $423,807.

E. Tree Trimming and Vegetation Management Expense.

283. OTP included in the test year its budgeted amount of this expense for 2010, approximately $1.393 million.[314] In the past five years, OTP has spent the following amounts for tree trimming and vegetation management:

	Total Company	Minnesota Jurisdiction
2005	2,677,153	1,274,593
2006	2,320,716	1,104,893
2007	3,067,120	1,460,256
2008	3,372,310	1,605,557
2009	2,493,047	1,186,940

284. In its last rate case, OTP sought and recovered $1,449,366 for the 2006 test year, on the basis that it had to increase this expense in future years in order to reduce storm-related outages.[315] OTP overspent this amount by $167,081 in 2007 and 2008 (combined); it underspent this amount by $262,426 in 2009.[316] According to OTP, its expenditures were lower than planned in 2009 because February snow levels were abnormally deep, preventing access to transmission lines. In addition, OTP avoided contract labor expense in May through July 2009 in response to economic pressures.[317]

285. The OAG objects to OTP's proposed expense, on the basis that it did not spend its budgeted amount for 2009. It proposes setting the expense at the five-year average of $1,326,448, or a reduction to the test year of $67,000.[318]

286. The record supports the adjustment proposed by the OAG. The Administrative Law Judge recommends setting this expense based on the five-year average of $1,326,448.

F. Lobbying Expense.

287. OTP did not explicitly include any lobbying expense in the test year. It records its lobbying expenses below the line so that those costs can be excluded from the revenue requirement.[319]

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[314] Ex. 4, OTP Initial Filing Vol. 3, Schedule C-7; Ex. 59, Smith Direct at 42.
[315] Ex. 59, Smith Direct at 42.
[316] Ex. 36, Beithon Rebuttal at 17.
[317] *Id*. at 18.
[318] Ex. 59, Smith Direct at 42-43.

288. The OAG contends that organizational dues for membership in the Edison Electric Institute (EEI) and the Lignite Energy Council (LEC) are spent, in part, on lobbying, and it proposed to exclude approximately $90,000 in dues for this reason. It also proposes to exclude corporate aircraft expenses associated with attendance at four meetings sponsored by these organizations and one meeting sponsored by the Chamber, on the basis that some portion of these expenses is for lobbying.[320]

289. In response, OTP provided evidence that the EEI and LEC identify on their billing statements the portion of dues charged for lobbying activities and that this portion of those expenses was excluded from the test year.[321] OTP also agreed to exclude $8,035 ($3,878 on a Minnesota jurisdictional basis) in directly assigned aircraft expense in order to eliminate this dispute with the OAG.[322]

290. In rebuttal, the OAG contended that the salaries and expenses of three OTP employees who are registered lobbyists (Loren Laugtug, Kevin Kouba, and Mark Bring) should be excluded from recovery by ratepayers.[323]

291. In surrebuttal, the OAG maintained that some portion of costs recorded to OTP's Legislative Monitoring and Review account ($75,024 on a total company basis, $37,512 for the Minnesota jurisdiction) should be excluded, along with overhead expenses pertaining to use of the aircraft. The OAG indicated that 18% of aircraft overhead (which amounted to $133,191 on a total company basis for the test year) should be excluded. This proposal is apparently based on the OAG's conclusion that five of the 28 trips (18%) using the corporate aircraft were to attend these meetings, which the OAG characterizes as "lobbying trips." The OAG also asserted that all aircraft expense should be removed from the test year because, if nearly 20% of its flights "may have involved lobbying activities," the aircraft is not necessary for the provision of utility service.[324]

292. As a policy matter, the Commission has long approved the recovery of a utility's membership dues in the EEI and LEC. For that reason, the OES has recommended approval of the dues paid by OTP to those organizations in this case.[325] Moreover, OTP has demonstrated that the portion of dues attributable to lobbying activity by these organizations has been excluded from recovery. The OAG's characterization of all activities relating to these organizations (whether the activity involves payment of dues or the expenses associated with attending meetings) as "lobbying" is without basis.

293. As a regulated utility OTP is obligated to monitor legislative activity and review legislation in order to appropriately anticipate and manage issues that may affect

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[319] Ex. 27, Wasberg Supplemental Direct at 3-4.
[320] Ex. 59, Smith Direct at 47-49.
[321] Ex. 36, Beithon Rebuttal at 20.
[322] *Id*.
[323] Ex. 66, Smith Rebuttal at 26.
[324] Ex. 67, Smith Surrebuttal at 60.
[325] *See* Finding No. 439.

its customers. Legislative monitoring and review includes passive observation of legislative proceedings about proposed legislation, review of pending legislation, and reporting on the status of legislation to operational employees on issues such as federal and state tax provisions related to wind projects and changes to eminent domain laws.[326] Lobbying, on the other hand includes active direct or indirect communication with legislative or executive officials for the purpose of influencing legislative action.[327] OTP's legislative review and monitoring expenses are not impermissible lobbying expenses.

294. With regard to the specific employee expenses to which the OAG objected, Kevin Kouba is an Area Manager in the Milbank, South Dakota, Customer Service Center. His responsibilities include managing operations in South Dakota and part of Minnesota. Mark Bring is associate general counsel of OTC, assigned to provide professional legal counsel to OTP. He advises OTP on a full range of legal issues, including environmental law, contract negotiations, litigation management, and permit proceedings. Loren Laugtug's duties primarily involve legislative services in Minnesota. Each of these employees is also a registered lobbyist. For each of them, OTP excluded lobbying activity and separately reported legislative monitoring expenses.[328]

295. OTP has demonstrated that it has policies in place to ensure that lobbying activity is excluded from the revenue requirement and that legislative review and monitoring is not lobbying but is a necessary cost of service. The OAG has failed to show that any additional sums attributable to these employees for legislative monitoring should be excluded because they are inappropriate lobbying expenses.

296. For all the above reasons, the Administrative Law Judge recommends that the Commission reject the adjustments proposed by the OAG for "lobbying expense," except for the expense ($8,035 total company, $3,878 on a Minnesota jurisdictional basis) that OTP agreed to remove.

G. Travel, Entertainment, and Related Employee Expenses.

297. OTP provides electric service in a large and rural service territory covering roughly 50,000 square miles.[329] Travel is necessary to provide service to OTP customers, and it is reasonable for OTP employees to incur transportation, lodging, and meal expenses while traveling within the service territory. For example, OTP has approximately 200 front-line field service employees (this is more than 25% of OTP's total workforce).[330] These employees perform line-work, meter-reading, service hook-up and disconnection work and numerous other duties necessary for providing service to customers.[331] It is also necessary for OTP employees to travel, at times for long distances, to assist on large projects and for other purposes, such as to and from OTP's

[326] Ex. 30, Wasberg Surrebuttal at 25.
[327] *Id*.
[328] *Id*.
[329] *Id*. at 3-4.
[330] *Id*.
[331] *Id*.

customer service centers and warehouse facilities for meetings, training, and other purposes.[332]

298. OTP has a detailed expense reimbursement policy (effective July 2006) that requires submission of expense reports signed by the employee and supervisor that document the amount and business purpose of any expense. The policy prohibits excessive, imprudent, or undocumented travel or entertainment expenses.[333]

299. The Minnesota Legislature passed Minn. Laws 2010, Ch. 328, effective August 1, 2010. Although the new legislation was not in effect at the time of OTP's current rate case filing, OTP agreed to comply with its requirements, and the Commission incorporated this agreement into its Order Accepting Filing, Suspending Rates, Extending Suspension Period, and Requiring Supplemental Filing.[334] OTP is the first utility to file for recovery of employee travel and entertainment expenses under the New Legislation.

300. The legislation, codified at Minn. Stat. § 216B.16, subd. 17(a), provides as follows:

> Subd. 17. Travel, entertainment, and related employee expenses. (a) The commission may not allow as operating expenses a public utility's travel, entertainment, and related employee expenses that the commission deems unreasonable and unnecessary for the provision of utility service. In order to assist the commission in evaluating the travel, entertainment, and related employee expenses that may be allowed for ratemaking purposes, a public utility filing a general rate case petition shall include a schedule separately itemizing all travel, entertainment, and related employee expenses as specified by the commission, including but not limited to the following categories:
>
> (1) travel and lodging expenses;
> (2) food and beverage expenses;
> (3) recreational and entertainment expenses;
> (4) board of director-related expenses, including and separately itemizing all compensation and expense reimbursement;
> (5) expenses for the ten highest paid officers and employees, including and separately itemizing all compensation and expense reimbursements;
> (6) dues and expenses for memberships in organizations or clubs;
> (7) gift expenses;
> (8) expenses related to owned, leased, or chartered aircraft; and
> (9) lobbying expenses.

[332] Id.
[333] Ex. 14, Brause Direct at 35-36 and Schedule 3.
[334] *In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Utility Service in Minnesota*, E-017/GR-10-239, Order Accepting Filing, Suspending Rates, Extending Suspension Period, and Requiring Supplemental Filing (May 27, 2010).

301. In addition, Minn. Stat. §216B.16, subd. 17(b), provides:

> (b) To comply with the requirements of paragraph (a), each applicable expense incurred in the most recently completed fiscal year must be itemized separately, and each itemization must include the date of the expense, the amount of the expense, the vendor name, and the business purpose of the expense. The separate itemization required by this paragraph may be provided using standard accounting reports already utilized by the utility involved in the rate case, in a written format or an electronic format that is acceptable to the commission. For expenses identified in response to paragraph (a), clauses (1) and (2), the utility shall disclose the total amounts for each expense category and provide separate itemization for those expenses incurred by or on behalf of any employee at the level of vice president or higher and for board members. The petitioning utility shall also provide a one-page summary of the total amounts for each expense category included in the petitioning utility's proposed test year.

302. OTP timely filed and served Supplemental Direct Testimony and Schedules related to Travel, Entertainment, and Related Employee Expenses on June 28, 2010 (Supplemental Filing).[335] OTP used information from its existing accounting system to prepare the Supplemental Filing. Until now, the Company had no reason to enter a detailed narrative in its accounting records as to the business purpose of each expense.[336] As a consequence, its existing accounting system contains an "activity description" for each expense, rather than a business justification, although the purpose can often be gleaned from that descriptor or other information provided. Because of the limited narrative detail available on Schedule 5, the Administrative Law Judge allowed the OAG extra time to conduct discovery and permitted the OAG's initial testimony on these issues to be filed in rebuttal.[337] OTP has the ability to manually retrieve all receipts and expense reports for any particular line item on the schedule.[338]

303. OTP has claimed $3.73 million in travel and other employee expense, including fuel expense, on a total company basis; this amounts to $1.86 million for the Minnesota jurisdiction. The vast majority of the travel expense items relate to ground transportation, lodging, and meals within OTP's service territory.[339] The schedule pertaining to executive expenses (Schedule 7) contains only $55,267 in expenses for the total company.[340]

[335] OTP did not include in the revenue requirement any expenses of OTC officers or directors, or any lobbying expense. Because those expenses were not included, it did not file itemized schedules in these categories. *See* Ex. 27, Wasberg Supplemental Direct and Schedules at 3-4.
[336] Ex. 30, Wasberg Surrebuttal at 4.
[337] Order on Motion to Compel Compliance with Minn. Laws 2010, Ch. 328 (Sep. 20, 2010).
[338] Ex. 30, Wasberg Surrebuttal at 11-12.
[339] Ex. 27, Wasberg Supplemental Direct at 5 and Schedule 5; Ex. 30, Wasberg Surrebuttal at 7.
[340] Ex. 27, Wasberg Supplemental Direct at Schedule 7.

304. The OAG contends that the Company's expense filing is deficient in that it (1) does not contain the Minnesota jurisdictional portion of the expense; (2) fails to include the name of the employee (on Schedule 5) who is responsible for the expense, although Schedule 7 lists this information for the ten highest paid employees; and (3) fails to include adequate information about the business purpose of the expenses. The OAG does not dispute that OTP provided, in discovery, the Minnesota jurisdictional portion of the expense;[341] the name of the employee responsible for the expense;[342] live, sortable electronic versions of the schedules;[343] and a great deal of other information about the expenses reflected in the schedules. The OAG essentially recommends that all of these expenses should be excluded from the test year because of deficiencies in the filed schedules, without consideration of other information the Company provided in discovery.

305. As a preliminary matter, the Administrative Law Judge notes that the statute by its terms requires itemization of the date of the expense, the amount of the expense, the vendor name, and the business purpose of the expense. The separate itemization may be provided using standard accounting reports "already utilized by the utility" involved in the rate case, in a written format or an electronic format that is acceptable to the commission. The statute is intended to "assist the commission" in evaluating the expenses that may be allowed for ratemaking purposes; it does not contemplate, contrary to the OAG's position, that the Commission's consideration of these expenses should be limited to what is contained in the filed schedules.

306. The Administrative Law Judge has concluded that OTP's filed disclosures are adequate to comply with the statute. The schedules permit detailed scrutiny of the claimed expenses and allow the opportunity for the OAG or any other party to conduct targeted follow-up discovery with regard to any expense that appears to be excessive. In the future, to facilitate this examination, the Commission may want to require the Company to supplement the statutory filing by including employee names, the Minnesota jurisdictional share attributable to the expense, and a more specific description of the business purpose associated with the expense. OTP has suggested that it might not be possible to provide the level of detail demanded by the OAG in describing the business purpose of these expenses, and that may be true; however, if more detail is provided in the schedule, less work should be required in responding to discovery. The bottom line is that it is in the Company's interest to facilitate the disclosure and analysis of these expenses.

307. **Lodging.** The Company included $124,130 in lodging expenses for business travel in the revenue requirement.[344] The Company's policy requires

[341] Ex. 66, Smith Rebuttal at 6.
[342] Ex. 30, Wasberg Surrebuttal at 14.
[343] For example, Schedule 5 can be sorted to separate all meal, travel, and lodging expenses, or to exclude fuel expense.
[344] Ex. 30, Wasberg Surrebuttal at 7.

employees to provide receipts for all lodging expenditures, and employees are encouraged to stay in reasonably priced lodging when it is available.[345]

308. The OAG has recommended that the entire lodging expense be excluded from recovery because OTP's filing inadequately disclosed the business purpose of most trips and failed to identify the number of days of travel for each expense.[346]

309. The OAG has highlighted certain expenses that it believes might be unreasonable, assuming there is a legitimate reason for the travel. For example, OTP's president traveled to Arizona and incurred an expense of $645 at the Fairmont Hotel in Scottsdale. The OAG suggested that this expense would be unreasonable if for one or two nights.[347] In response, OTP provided evidence that the stay was for three nights to attend an EEI board meeting.[348] In addition, the OAG objected to lodging expenses in Maple Grove, Minnesota, and Lisbon, North Dakota, as being outside OTP's service area.[349] In response, OTP provided evidence that the Maple Grove expense was for an employee to attend a Midwest Transmission Group meeting held at Great River Energy's offices,[350] and the other expense was incurred by one of OTP's line crews to stay at the Super 8 Motel while working in Lisbon, North Dakota.[351]

310. Review of the Company's Schedule 5 lodging expenses confirms that the vast majority of these expenses are incurred within OTP's service territory at establishments such as AmericInn, Homewood Suites, Super 8 Motels, Best Western, and Hampton Inn, at rates between $65 and $100 per night. The Company appears to be enforcing its policy requiring reasonable lodging expense. OTP has demonstrated that its lodging expenses were reasonably incurred by employees in performance of their duties, and the amount of the claimed expense is reasonable.

311. **Meals and Entertainment.** OTP included $129,554.65 in meals and entertainment expenses in the revenue requirement.[352] The Company's policy requires detailed requirements for reimbursement of meal and entertainment expense.[353]

312. OAG opposes OTP's meals and entertainment expenses and recommends that the entire amount be excluded from recovery because Schedule 5 did not include the name of the employee incurring the expense and inadequately described the business purpose of the meal.[354] In response to an OAG information

[345] Ex. 14, Brause Direct at Schedule 3.
[346] Ex. 66, Smith Rebuttal at 14.
[347] Ex. 30, Wasberg Surrebuttal at 11-12.
[348] *Id*. at 18.
[349] Ex. 66, Smith Rebuttal at 13-14.
[350] Ex. 30, Wasberg Surrebuttal at 17.
[351] *Id*. at 18.
[352] Ex. 30, Wasberg Surrebuttal at 7.
[353] Ex. 14, Brause Direct at Schedule 3.
[354] Ex. 66, Smith Rebuttal at 13.

request, OTP provided the name of each employee incurring the meal expense.[355] It also provided a schedule with codes for different types of meal expenses.[356]

313. The OAG objected, for example to meal expense associated with the activity description "Provide Customer Assistance."[357] OTP provided evidence that this activity descriptor is defined to include "provide instructions or assistance to customers, the object of which is to encourage safe (proper use of equipment), efficient (replacement of such equipment), and economical use (information related to such equipment) of the utility's service. It also includes labor, supplies, and expenses pertaining to demonstrations, exhibits, lectures, and other programs."[358]

314. OTP's meal expense is generally spent at fast-food and various pizza establishments in OTP's service area. Employees who travel out of the service territory to more expensive cities tended to spend more on meals, but those visits are infrequent. Schedule 7 reflects that the president of the Company spent approximately $816 on meals (on a total company basis).[359] The Company has established that it is generally quite frugal with regard to meal expense and that its claimed expenses are reasonable.

315. **Travel.** OTP included $1.7 million in total company expense ($847,749 for the Minnesota jurisdiction) in travel expense.[360] The OAG has no objection to about $1.3 million of these total company expenses, which are associated with licensing, maintaining, and fueling OTP vehicles used for employee travel. It contends that these expenses should not have been included in the travel expense filing.[361]

316. It does object to $62,236 in expense associated with OTP's aircraft, and to the remaining expenses coded as "TRAV" on Schedule 5 on the basis that there is insufficient detail to justify recovery.[362]

317. As an example of an expense for which insufficient detail is provided, the OAG points to a mileage reimbursement check in the amount of $551.24 that does not indicate a destination. Its purpose is described as "Regulatory Review."[363] OTP provided evidence that the expense included total parking and mileage reimbursement for an employee who made several trips: Fergus Falls to Morris, round trip, for a public hearing held in Morris, Minnesota (108 miles @ .505 = $54.54); Fergus Falls to St. Paul,

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[355] Ex. 30, Wasberg Surrebuttal at 14.
[356] *Id*.
[357] Ex. 66, Smith Rebuttal at 10.
[358] Ex. 30, Wasberg Surrebuttal at 16-17. The two meal expenses in Minneapolis to which the OAG specifically objected (Brit's Pub and Morton's of Chicago) were incurred in connection with a meeting of the Minnesota School Board Association, at which OTP operated an information booth. They also met with the designer of large-scale heat pump systems to learn more about this technology. *See id*.
[359] Ex. 27, Wasberg Supplemental Direct at Schedule 7.
[360] Ex. 30, Wasberg Surrebuttal at 7.
[361] Ex. 66, Smith Rebuttal at 15.
[362] Id. at 16.
[363] Id. at 17.

twice, for evidentiary hearings (470 x 2 @.505 =$474.70); it also included parking expense for two days @$4.50, one day @$5.00, and one day @$8.00.[364]

318. The OAG pointed to other expenses reimbursed to three other employees as providing no indication what the expenses were for. OTP provided evidence that detailed the mileage for each employee for business trips between Fergus Falls and Fargo, Minneapolis, St. Paul, Morris, and Wahpeton and Jamestown, North Dakota.[365]

319. The above examples illustrate the difficulty involved in providing the level of detail requested by the OAG as a narrative description on the filed schedules. The disclosure on the schedule provides the information that the employees received reimbursement in the various amounts for business travel. There is no way that the amount of detail required to explain the various dates, trip mileage, and parking costs could be translated to a complete narrative description in the accounting project records. The schedules provide sufficient information, however, to facilitate further examination of the reasonableness of each expense.

320. OTP has established that its travel expenses are reasonable and necessary for the provision of utility service and that these expenses should be recovered in rates.

321. **Aircraft Expense.** The OAG also recommends that OTP's expenses associated with corporate aircraft ($185,335 on a total company basis) be denied, on the basis that OTP did not demonstrate that ownership of the corporate aircraft is necessary for the provision of utility service.[366] These expenses are reflected on Schedule 10 of OTP's Supplemental filing.

322. The OAG cited one example of a trip using the corporate aircraft that, in its view, is unnecessary. The trip was to a May 2009 annual meeting of Allete. OTP is legitimately concerned with the activities of other regional utilities.[367] It is reasonable and appropriate for OTP employees to monitor the annual meeting of another regional utility. The amount of expense associated with this trip was $1,440 on a total company basis (without overhead or depreciation).[368]

323. Schedule 10 also reflects that the corporate aircraft was used to attend public utility commission meetings in Minnesota, North Dakota, and South Dakota; meetings of the LEC; meetings with MISO; and meetings with the Department of Commerce, Enbridge, and the Chamber. This is all legitimate business travel.

324. Although the OAG suggests that the need for the aircraft should be justified based simply on the difference between its cost and what the mileage

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[364] Ex. 66, Smith Rebuttal at 17.
[365] Ex. 30, Wasberg Surrebuttal at 11.
[366] Ex. 66, Smith Rebuttal at 21. The $185,334.90 includes the $62,235.84 in expenses related to expense type TRAV and is a system wide amount. The Minnesota share is approximately 50 percent of the total.
[367] *Id*.
[368] *Id*.

reimbursement would have been had employees instead driven their vehicles, the costs associated with employee travel time should also be considered. OTP's service territory covers 50,000 square miles. Its offices are in Fergus Falls, a city with no commercial air service. It is regulated in three states. Its aircraft is a 1987 turboprop. It is clear that, without the aircraft, OTP employees would spend more time driving long distances.

325. The Commission has recently allowed other utilities to recover 50% of corporate aircraft costs, provided the utilities supported recovery with an appropriate cost-benefit analysis.[369] These utilities, however, are located in areas with commercial airline service; and OTP has proposed a relatively small expense for the Minnesota jurisdiction. The Administrative Law Judge recommends that the Commission permit OTP to recover 75% of these expenses at this time. If OTP seeks to recover more in its next rate case, it should provide a cost/benefit analysis that would more formally examine the costs and benefits of aircraft ownership.

326. **Gifts.** OTP included gift expense of $55,875 on a total company basis ($27,937 for the Minnesota jurisdiction).[370] The gift expense is contained on Schedule 9 of OTP's Supplemental Filing.

327. The OAG objects to OTP's recovery of any gift expenses, on the basis that it is not the type of expense necessary for the provision of utility service.[371]

328. The bulk of the expense disclosed on the schedule is for "MTM Recognition," which is a reference to the vendor that provides employee recognition awards. OTP incurred these expenses for its employee "annual gift," which it describes as being "intended to foster employee loyalty and morale" and is presented "with a safety message to promote a culture of safety in the workplace."[372]

329. The Commission has determined that employee gift expenses of this sort are not appropriate for recovery in rates.[373] Although rewards associated with safety incentives were permitted in Minnesota Power's last rate case, OTP has not sufficiently tied these expenses to any safety incentive program. The Administrative Law Judge accordingly recommends that OTP's gift expenses be excluded from the test year.

IX. CAPITAL STRUCTURE, COST OF DEBT, ROE, and ROR.

330. OTP proposed the following capital structure and cost of debt, resulting in an overall Rate of Return (ROR) of 8.88 percent:[374]

[369] *Minnesota Power*, Order at 33-34.
[370] Ex. 30, Wasberg Surrebuttal at 7.
[371] Ex. 66, Smith Rebuttal at 18.
[372] Ex. 30, Wasberg Surrebuttal at 22.
[373] *Minnesota Power*, Order at 32.
[374] Ex. 18, Moug Rebuttal, Schedule 1. The cost of long-term debt reflected above (6.69 percent) might need to be recalculated to reflect the Company's acceptance of the 2.85 percent cost of variable rate debt recommended by the OAG. *See* Finding Nos. 372-73.

	Amount	Percent of Total	Cost	Weighted Cost
Long-Term Debt	$288,367,295	45.50%	6.69%	3.04%
Short-Term Debt	$17,956,893	2.80%	0.79%	0.02%
Common Equity	$328,112,867	51.70%	11.25%	5.82%
Total		100.0%		8.88%

331. The OES agreed with (1) OTP's capital structure, including OTP's amounts of long-term debt, short-term debt, and common equity; (2) OTP's cost of long-term debt; (3) OTP's cost of short-term debt; and (4) the resulting weighted cost of long-term debt and weighted cost of short-term debt.[375] OES disagreed with the proposed return on equity (ROE), recommending an ROE of 10.74 percent and a resulting overall ROR of 8.62 percent.[376]

332. The OAG disagreed with OTP's proposed short-term debt balance and with several components of OTP's proposed costs of long-term debt.

A. Capital Structure.

1. Long-Term Debt Balance.

333. The long-term debt in the OTP capital structure is based on the six-month average data for the period ended December 31, 2009, adjusted to remove the $75 million two-year note that was used to provide financing for the Luverne Wind Project. It reflects the long-term debt components in OTP's permanent capital structure, along with their costs.[377]

334. The OES agreed with OTP's proposed long-term debt balance.[378] The OAG did not object to OTP's long-term debt balance, but its proposal with regard to short-term debt balance would impact the long-term debt balance.

2. Short-Term Debt Balance.

335. As noted above, the Company made adjustments to remove the effects of the Luverne Wind Project from long-term debt balances. Similar adjustments were made with regard to OTP's short-term debt balances. OES agreed with OTP's proposed short-term debt balance.[379] The OAG objected, maintaining the short-term debt balance should be $35,718,092.[380]

[375] Ex. 76, Griffing Surrebuttal at 12-13, 20.
[376] *Id*. at 20.
[377] Ex. 17, Moug Direct at 4; Ex. 18, Moug Rebuttal at 17-18.
[378] Ex. 76, Griffing Surrebuttal at 12-13, 20.
[379] *Id*.
[380] Ex. 67, Smith Surrebuttal at 25.

336. The Luverne Wind Project is a 169.5 MW nameplate capacity wind farm located in Steele County, North Dakota.[381] OTP invested approximately $100.6 million in the project, in order to supplement existing generation needs and to meet renewable portfolio standards in Minnesota, North Dakota, and South Dakota.[382] The Commission approved OTP's investment in the project.[383]

337. Construction began in the second quarter of 2009 and was completed in September 2009. Capital market conditions in this timeframe posed significant obstacles to financing the project.[384] The American Recovery and Reinvestment Act of 2009 made available a $30 million U.S. Treasury grant for construction of renewable energy projects, to be provided 60 days after the project was put into operation. The availability of this grant made it feasible for OTP to obtain a $75 million, two-year term loan in May 2009 to finance the wind project.[385]

338. In October 2009, OTP received the $30 million Treasury Grant and used it to pay down $17 million on the two-year term loan and to pay for project expenditures.[386] In January 2010, the remaining $58 million loan was paid off, in large part as a result of a $50 million borrowing on OTP's revolving credit facility. This caused a temporary (four-month) but substantial increase in OTP's short-term debt balance.[387] OTP's short-term debt was paid down by the application of a tax refund received in early May 2010.[388]

339. OTP removed all of the temporary debt financing for the project from its capital structure because the debt was a temporary financing event, and it was not representative of OTP's typical operations.[389]

3. Equity Ratio.

340. The financing of the Luverne project had short-term effects on other elements of OTP's capital structure before, during, and after the financing period. The OTP divisional capital structure contained an average equity ratio of 51.7% for the period December 31, 2008 to April 30, 2009. From May 2009 (when financing began) to May 2010, OTP's equity ratio ranged from 46.2 percent to 48.9 percent.[390] From May 2010 through December 2010, OTP projected a 51.9 percent equity ratio.[391]

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[381] *See* Finding No. 65.
[382] Ex. 17, Moug Direct at 12.
[383] *Id*.; *In the Matter of Otter Tail Power Company's Petition for Approval of the Luverne Wind Project*, Docket No. E-017/M-09-883, Order Approving Investment in Affiliated Interest Project, with Clarifications (Jan. 27, 2010).
[384] Ex. 17, Moug Direct at 12-13.
[385] *Id*.
[386] *Id*.
[387] *Id*.
[388] Ex. 18, Moug Rebuttal at 18.
[389] *Id*. at 17-18.
[390] Ex. 17, Moug Direct, Schedule 6.
[391] Ex. 18, Moug Rebuttal, Schedule 2.

341. OTP's proposed 51.7 percent equity ratio is consistent with the target equity ratios that have been maintained for OTP over several years and is consistent with future targets. OTP's proposed 51.7 percent equity ratio is also consistent with actual data for March through September 2010, and updated projections for October through December 2010.[392]

342. The OES agrees with the proposed equity ratio.[393]

343. Although the OAG did not specifically dispute OTP's equity ratio in this case, the implementation of the OAG's recommendation on short-term debt balances would also impact OTP's equity ratio. If the OAG's proposal regarding short-term debt balance were accepted, it would affect OTP's capitalization as follows: short-term debt, 5.48%; long-term debt, 44.21%; common equity, 50.31%.[394]

344. OTP's approach to financing the Luverne project temporarily caused its equity ratio to drop below typical levels, but it provided significant benefits to ratepayers. The use of the Treasury Grant resulted in a $30.2 million reduction to rate base, allowing the completion of construction without incurring high long-term capital costs and preserving OTP's liquidity.[395]

345. The Administrative Law Judge recommends that the Commission approve OTP's proposed capital structure and reject the adjustment proposed by the OAG to the short-term debt balance. The OAG's proposed adjustment would result in a non-representative capital structure for OTP for the period of time these rates will be in effect.

B. Cost of Long-Term Debt.

346. OTP's proposed cost of long-term debt reflects its actual interest expenses. The OES agreed with OTP's proposed costs of long-term debt.[396]

347. The OAG disagreed with several of the actual interest rates included in OTP's cost of long-term debt, and recommended that several reductions be imputed to the Company for ratemaking purposes.[397] The OAG's recommendations are based on the hypothetical refinancing of debt associated with the holding company reorganization. The OAG's proposed interest rate cost reductions amount to approximately $1,237,000 per year[398] and would result in a 1.18 percent reduction in OTP's long-term debt interest cost (from 6.69 percent to 5.51 percent).[399]

[392] Ex. 18, Moug Rebuttal at 3 and Schedule 2.
[393] Ex. 76, Griffing Surrebuttal at 12-13, 20.
[394] Ex. 76, Smith Surrebuttal at 27.
[395] Ex. 17, Moug Direct at 15.
[396] Ex. 76, Griffing Surrebuttal at 12-13, 20.
[397] Ex. 67, Smith Surrebuttal at 5-31.
[398] Ex. 38, Beithon Surrebuttal at 14.
[399] Ex. 20, Moug Surrebuttal, Schedule 6.

348. On July 1, 2009, OTP became a wholly owned subsidiary of OTC, a public utility holding company. Prior to this date, OTP had been an operating division of OTC, and the portions of debt relating to the utility were internally assigned to OTP.

349. On June 3, 2008, OTC filed an application for approval of the proposed restructure with the Commission.[400] Its application provided, in relevant part, as follows:

> In preparation for the Transactions, the Company will identify all existing indebtedness as being allocated to Holding Company or New Otter Tail Utility, as appropriate. The objective of the allocation will be to ensure that New Otter Tail Utility will not be obligated on any of the Company's current indebtedness attributable to non-utility operations. The existing indebtedness categorized as "utility" will remain indebtedness of New Otter Tail Utility by operation of law, unless redeemed or refinanced. . . . *The final allocation of indebtedness will depend on the extent to which necessary third party consents, or necessary refinancing, can be obtained on commercially reasonable terms.* Subsequent to the Commission's order herein and prior to the effective date of the Transactions, New Otter Tail Utility will make a capital structure approval filing under Minnesota Rules 7825.1400 describing the exact capital structure resulting from the process.[401]

350. The OAG actively participated in the Reorganization docket.

351. In September 2008, OTC reassigned $57 million in debt to OTP. The holders of these notes required reassignment prior to formation of the holding company, and the debt was reassigned at this time in connection with OTC's equity offering and the financing of the Ashtabula Wind Project (a utility project). In about this same timeframe, OTC contributed $63 million in cash to OTP.[402]

352. On January 7, 2009, the Commission approved the reorganization subject to a number of conditions, one of which was that within 60 days of completion of the restructuring, OTP had to file with OES and the Commission the Company's pre- and post-restructuring capital structures together with the cost rate for each component and explanations of any changes.[403] The Commission's order expressly provided for the OAG to continue its participation in the capital structure docket by ensuring that the OAG had access to all of the Company's books and records, including all records of OTC and its subsidiaries, on the same basis that these records were available to OES and the Commission. In addition, the order provided that "OTP shall request and obtain

[400] *In the Matter of the Application of Otter Tail Corporation Under Minnesota Statutes, Section 216B.50 to Form a New Holding Company*, Docket No. E-017/PA-08-658, Initial Filing (June 3, 2008).
[401] *Id*. at 4 (emphasis added).
[402] Ex. 17, Moug Direct at 10; Tr. 1:53, Moug.
[403] *In the Matter of the Application of Otter Tail Corporation Under Minnesota Statutes, Section 216B.50 to Form a New Holding Company, Docket No. E-017/PA-08-658,* Order Approving Reorganization, as Conditioned, at Ordering Clause 3, p. 4 (Jan. 7, 2009).

Commission approval pursuant to Minn. Stat. § 216B.48 *and/or Minn. Stat. § 216B.49* before it includes any debt provided by Otter Tail Corporation in its capital structure."[404]

353. On August 28, 2009, OTP filed a petition for approval of its 2009 capital structure. The petition sought approval of the pre- and post-restructuring capital structures of the Company, as required by the Commission's earlier order. The filings reflected an increase in overall cost of capital (from 8.01% to 8.11%) due to an increase in the cost of long-term debt and the substitution of an inter-company note for OTP's preferred stock.[405]

354. As OTP indicated in its initial filing with the Commission, the reassignment of existing debt from OTC to OTP required lender consent.[406] In connection with the reorganization, some of the lenders required that the debt be assigned exclusively to OTC, and some required that the debt be assigned exclusively to OTP, regardless of the proportions internally assigned to the utility.[407] Cash payments and other debts were shifted between the two entities to offset the increased debt assignments to OTP.

355. The net effect of these changes was an increase in OTP's long-term debt in the amount of $24.4 million, and its blended interest rate for long-term debt increased by 25 basis points (from 5.81 percent to 6.06 percent).[408] In exchange, OTC contributed $24.4 million in cash to OTP, which was used to fund capital expenditures.[409] The OES approved the reasonableness of these transfers, on the basis that the notes were used for utility purposes prior to the restructuring, and recommended that the Commission approve it. In contrast to the Reorganization docket, the OAG filed no comments in this docket. The Commission approved the proposed capital structure on November 10, 2009.[410]

356. The OAG argues generally that OTP failed to seek approval for the 2008 and 2009 debt transfers in an affiliated interest docket under Minn. Stat. § 216B.48, and that because the Company failed to do so, the OAG would undertake scrutiny of the transfers in this docket. The Administrative Law Judge disagrees with the premise of this argument. The September 2008 transfers occurred while the Reorganization docket was pending, and the Commission's order in that docket provided that OTP could obtain Commission approval of debt transfers to OTP through either an affiliated interest filing under Minn. Stat. § 216B.48 or a capital structure filing under Minn. Stat. §

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[404] *Id*. at Ordering Clause 7 & 8(d), pp. 4-5 (emphasis added).
[405] *In the Matter of the Petition of Otter Tail Power Company for Approval of 2009 Capital Structure and Permission to Issue Securities*, Docket E-017/S-09-1018, Initial Filing and Attachment 11 (Aug. 28, 2009).
[406] Ex. 18, Moug Rebuttal at 5; Tr. 1:63-64, Moug.
[407] For example, prior to formation of the holding company, $45 million of a $50 million obligation (Series D senior note at 6.47%) had been internally assigned to OTP; afterward, $50 million was assigned to OTP. In addition, $36 million of a $90 million obligation (Series 2011 notes at 6.63%) had been internally assigned to OTP, whereas after the reorganization $90 million was assigned to OTP. Ex. 17, Moug Direct at 9.
[408] Ex. 17, Moug Direct at 11.
[409] *Id*. at 10.
[410] *In the Matter of the Petition of Otter Tail Power Company for Approval of 2009 Capital Structure and Permission to Issue Securities*, Docket E-017/S-09-1018, Order (Nov. 10, 2009).

216B.49. It is clear that the September 2008 and 2009 transfers were fully disclosed and that the Commission approved the Company's resulting capital structure in November 2009.[411] The OAG's post-hoc criticism of these transfers cannot be justified on the basis that the Company failed to seek approval of them.

1. 2009 Debt Transfers.

357. In addition, the OAG argued that OTC shifted low-interest debt to itself and high-interest debt to OTP, lowering its cost of capital and inappropriately increasing OTP's cost of capital. It contends the Commission should apply what it characterizes as the market interest rate of 4.5 percent in 2009 to the $24.4 million in increased debt, which would reduce OTP's annual interest cost by 18 basis points, or $517,280.[412] This proposed interest rate is based on the yield on short-maturity, three-year Treasuries (with an average yield of 1.57 percent) plus OTP's 2007 spread (1.55 percent).[413] It is unclear why the OAG assumes that use of OTP's 2007 spread would be a valid predictor of market rates for utility debt in a year other than 2007, especially considering the increase in spread between Treasuries and utility bonds during the financial crisis of 2008 and 2009.[414]

358. In response, the Company contends that the only debt shifted to OTC was $34.6 million of 5.778 percent 10-year debt, which was re-priced by the lender at 8.89 percent.[415] The Administrative Law Judge agrees that OTC did not shift low-cost debt to itself.

359. Moreover, OTP disputes that the market rate for long-term debt in 2009 was 4.5 percent, and it further disputes that refinancing at this time would have resulted in lower effective interest rates on the debt. OTP presented evidence that in May through June 2009, long-term interest rates for unsecured debt of utility borrowers with credit ratings similar to that of OTP ranged from 7.625 percent to 9 percent. When secured transactions are considered, along with utility borrowers with somewhat better credit ratings, the coupon rate averaged 7.54 percent.[416] In contrast, the interest rates on the debt assigned to OTP in 2009 were 6.37 percent (for $25 million of 20- year debt), 6.47 percent (for $5 million of 30-year debt), and 6.63 percent (for $54 million of 10-year debt). The interest rates on the debt assigned to OTP were lower than the refinancing rates OTP would have incurred, without consideration of the effects of make whole obligations.

360. As OTP points out, all of this debt contained make-whole obligations, which would have required the borrower to make an added substantial payment based

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[411] *In the Matter of the Petition of Otter Tail Power Company for Approval of 2009 Capital Structure and Permission to Issue Securities*, Docket E-017/S-09-1018, Initial Filing and Attachments 6, 10, 10A, and 11 (Aug. 28, 2009).
[412] Ex. 59, Smith Direct at 6-8.
[413] Ex. 66, Smith Rebuttal at 34.
[414] Tr. 1:60-63, Moug.
[415] Ex. 59, Smith Direct at 4.
[416] *Id*. at 9.

on the net present value of the future debt payments.[417] Make whole obligations increase the cost of refinancing for borrowers by increasing the amount of capital needed to refinance (by the amount of the make whole payment), which increases the effective interest rate. This higher cost is amortized over the term of the new debt as a cost of refinancing. Had OTP refinanced this debt, the make whole obligations would have been its responsibility, not that of OTC. The make whole obligations would have further increased the cost of the debt reassigned to OTP in 2009 and would have resulted in effective interest rates of 7.52 percent to 9.59 percent.[418]

2. 2008 Debt Transfer.

361. Second, the OAG argued that the $57 million in debt reassigned from OTC to OTP in 2008, in anticipation of the reorganization, should be assigned an interest rate of 5.823 percent for ratemaking purposes, in lieu of the weighted average 6.43 percent interest attached to the debt.[419] This interest rate represents the yield on 30-year U.S. Treasuries (4.28 percent) plus OTP's spread (1.55 percent) on 2007 borrowings.[420]

362. OTP again disputed the need for and basis for this proposed adjustment. It provided evidence that interest rates for secured and unsecured loans made to utility borrowers with credit ratings slightly better than OTP's averaged 7.52 percent in September through December 2008.[421] In contrast, the interest rates on the debt assigned to OTP in 2008 were 6.37 percent (for $25 million of 20- year debt) and 6.47 percent (for $32 million of 30-year debt). When make whole obligations are considered, the effective interest rate on this debt would have been between 8.16 and 9.71 percent, had OTP refinanced this debt in 2008.[422]

363. The premise of the OAG's arguments with respect to the long-term cost of this debt is that OTC profited by assigning high-interest debt to OTP when the Company was reorganized. The Company has established that its lenders controlled those decisions and that refinancing this debt, in either 2008 or 2009, would likely have cost ratepayers substantially more than the interest rates proposed by the OAG. The Company has established that its proposed long-term cost of debt is reasonable, and the Administrative Law Judge recommends that the two adjustments proposed by the OAG be rejected.

3. Inter-Company Note.

364. Third, the OAG contends that the intercompany note OTP assumed in the amount of $15.5 million, at a weighted average interest rate of 7.11 percent, was above market rate. It argues OTP could have raised this sum in capital markets at a lower

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[417] Ex. 18, Moug Rebuttal at 6.
[418] *Id*. at 11.
[419] Ex. 66, Smith Rebuttal at 33-37.
[420] *Id*. at 34-35.
[421] Ex. 18, Moug Rebuttal at 13.
[422] *Id*.

interest rate and could still refinance this debt at any time. The OAG recommends that the commission reduce the interest rate to 3 percent, which is the rate for long-term variable debt, as a proxy for the market rate. This adjustment would reduce OTP's cost of debt by 21 basis points, or $616,500.[423] In the alternative, the OAG would find it acceptable if OTP committed to refinancing this note at 4.32 percent interest before December 31, 2011.[424]

365. Prior to the holding company reorganization, $15.5 million of preferred stock had been part of the permanent capital of OTP. The $15.5 million of intercompany debt was the result of Otter Tail Corporation taking financial responsibility for that $15.5 million of preferred stock because of the terms of the preferred stock. The 7.11 percent interest rate (which is tax deductible to OTP) matched the after-tax cost that OTP had been incurring in connection with the dividends that OTP had been paying on this preferred stock (which are not tax deductible).[425] Thus, the cost for OTP remained unchanged.[426]

366. Moreover, there is no basis to assume that a variable rate of interest should be applied to this note, because the preferred stock was a permanent (not short-term) source of capital to OTP and is now a permanent source of capital to Otter Tail Corporation. Further, the dividends on the preferred stock are at fixed rates, not at variable rates.

367. A 7.11 percent interest rate was well in the range of market rates for long-term debt in June 2009 (which had an average interest rate of 7.54 percent), even before considering the effects of the "call premiums" that are applicable to the $15.5 million of preferred stock.[427] Call premiums, which are similar to make whole obligations on loans, are amounts that must be paid to the holders of preferred stock in order to retire the preferred stock.[428] OTP presented evidence that it would have incurred an effective interest rate of 7.63 percent if it had refinanced the preferred stock at 7.54 percent and 7.96 percent if it refinanced at 7.875 percent. Both rates are higher than the 7.11 percent intercompany rate.[429]

368. Based on this evidence, the Administrative Law Judge recommends that the OAG's proposed adjustment to the terms of the inter-company note be rejected. OTP has established the reasonableness of the interest rate of this component of its long-term debt cost.

369. In summary, the Administrative Law Judge notes that the Commission approved OTP's proposed capital structure in November 2009. That proposal reflected all of the debt assignments in 2008 and 2009 that the OAG disputes here. The OAG did

[423] Ex. 59, Smith Direct at 11.
[424] Ex. 67, Smith Surrebuttal at 19.
[425] Ex. 18, Moug Rebuttal at 14.
[426] *Id*. at 15.
[427] *Id*. at 16.
[428] *Id*.
[429] *Id*.

not file comments in that docket and has failed to provide persuasive evidence in this docket that those transfers inappropriately inflated OTP's costs of debt. OTP has established that its proposals are reasonable and reflect its true costs; it has also established that refinancing in 2008 or 2009 would have increased those costs.

4. Debt Maturing in 2011.

370. Finally, the OAG contends that, with respect to the debt that matures in 2011, the Commission should substitute the existing interest rate of 6.63 percent with the average interest rate from OTP's remaining debt.[430]

371. OTP presented evidence that it has considered early refinancing of a portion of the debt that is due to be repaid on December 1, 2011, but it has not made a decision to refinance, and it has not taken any steps to refinance the debt thus far. The Administrative Law Judge concludes that any potential refinancing in 2011 would not be a known and measureable change to OTP's 2009 test year.

5. Variable Rate Debt.

372. OTP originally proposed an interest rate of 3.58 percent in calculating the weighted cost of long-term debt. In response, the OAG recommended using a 3 percent rate instead, on the basis that rates in September 2010 were somewhat lower.[431] OTP calculated the average rate in effect from January through September 2010, which was 2.97 percent. It then agreed to use the 3 percent rate recommended by the OAG. This adjustment produced the 6.69 percent cost of long-term debt OTP proposes in this case.[432]

373. In surrebuttal, the OAG proposed a further decrease in the cost of variable debt. It proposed setting the variable rate debt at 2.85 percent, which would be the average rate for January through December 2010, assuming that no further changes took place between October and December.[433] In the alternative, the OAG proposed an adjustment reflecting the actual 2010 average rate, whatever it might be, at year end. It appears that OTP accepted the proposal to set variable rate debt at 2.85 percent;[434] however, it is not clear to the Administrative Law Judge whether that reduction is reflected in the 6.69 percent long-term debt rate proposed by the Company.

C. Return on Equity.

374. To provide service, a utility must be able to compete for necessary funds in the capital markets. To attract these funds, the utility must earn enough to offer competitive returns to investors. The basic standards for the determination of ROE are found in the United States Supreme Court's decisions in Hope[435] and Bluefield[436] and in

[430] Ex. 66, Smith Rebuttal at 37-38.
[431] Ex. 59, Smith Direct at 15-16.
[432] Ex. 18, Moug Rebuttal at 25 & KGM-2, Schedule 13.
[433] Ex. 67, Smith Surrebuttal at 30-31.
[434] Tr. 3:16, Smith.
[435] *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) (*Hope*).

Minn. Stat. § 216B.16. Hope and Bluefield standards require: (1) a return consistent with other businesses having similar or comparable risks; and (2) a return adequate to support credit quality and access to capital, while maintaining financial integrity. Minn. Stat. § 216B.16 refers to "the need of the public utility for revenue sufficient to enable it … to earn a fair and reasonable return upon [its] investment."

375. OTP recommends a return on equity (ROE) of 11.25 percent. The OES recommends an ROE of 10.74 percent.[437]

376. The analyses and recommendations by OTP and OES are relatively consistent and are based on generally similar analytic inputs, including growth rates and comparable companies; are primarily based on the constant-growth Discounted Cash Flow (DCF) model; include recovery of flotation costs under the Commission's traditional method of recovery; and are corroborated by Capital Asset Pricing Model (CAPM) analyses.

1. Comparable Groups.

377. The selection of comparable groups is intended to identify electric service companies that have investment risk similar to that of OTP. OTP's expert used a comparable group (OTP Proxy Group) of nine electric utilities.[438] OES also used a final comparable group (OES Electric Service Group) that included nine electric utilities.[439]

378. The OTP revised Proxy Group included American Electric Power; Cleco Corp.; Empire District Electric; Great Plains Energy; IDACORP Inc.; Pinnacle West Capital; Westar Energy; Northeast Utilities; and Portland General.[440]

379. The OES revised Electric Service Group included American Electric Power; CLECO Corp.; DTE Energy Co.; Edison International; Empire District Electric; Great Plains Energy; IDACORP, Inc.; Pinnacle West Capital Corp.; and Westar Energy.[441] A comparison of OTP's capital structure to that of the OES comparison group reflects that OTP has a slightly higher equity ratio and less overall debt.[442]

380. OTP excluded DTE Energy (included in the OES group) from its proxy group on the basis that it did not derive 90% of its total regulated net income from regulated electric operations, which was the screening criteria OTP used.[443]

381. OES excluded two companies in OTP's group (Northeast Utilities and Portland General) for different reasons. Northeast Utilities was excluded from the OES

[436] *Bluefield Waterworks Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923) (*Bluefield*).
[437] Ex. 76, Griffing Surrebuttal at 20.
[438] Ex. 21, Hevert Direct at 11; Ex. 22, Hevert Rebuttal at 10.
[439] Ex. 76, Griffing Surrebuttal at 4-6.
[440] Ex. 21, Hevert Direct at 14; Ex. 22, Hevert Rebuttal at 10.
[441] Ex. 73, Griffing Direct at 14-15; Ex. 76, Griffing Surrebuttal at 4-6.
[442] Ex. 73, Griffing Direct at 18-20.
[443] Ex. 22, Hevert Rebuttal at 10.

comparable group because its income from regulated electric business fell below the 60% threshold OES used to screen the comparable group. OES excluded Portland General because its credit rating of BBB+ is higher than other companies in the group.[444]

382. One of OTP's screening criteria in selecting a comparable group was the exclusion of utilities without at least 10 percent coal-fired generation, on the basis that investors see coal generation as having greater risk than utilities relying on other forms of generation.[445] The OAG objected to use of this screening criteria, arguing that by selecting a higher-risk proxy group, OTP is receiving the benefit of additional financial recovery for the risks associated with coal generation, including the cancellation of coal plants. It argues that "any further recovery of purported costs associated with Big Stone II represents a form of double recovery and should be rejected."[446]

383. The OES did not use this screen for selecting its comparable group, which turned out to be very similar to that of OTP. The Administrative Law Judge cannot conclude from the record that the differences between the OES and OTP comparable groups are due to use of this screen or that the cost of equity recommended in this Report has been increased in any way to compensate OTP for risks associated with Big Stone II.

2. The DCF Model.

384. The DCF model is widely used to determine the ROE for utilities and has sound theoretical basis. The Commission has historically relied primarily on the DCF model.[447]

385. Under the Constant Growth DCF model, the price of a stock is a function of the collective ROE required by investors, which is the sum of dividend yield and the expected long-term growth-rate.[448] The dividend yield can be measured from the current dividends and stock price of a company. The expected long-term growth rate is based on the analyst's judgment.

386. Both OES and OTP used analysts' forecasts of earnings per share growth to determine the growth component of the DCF model. This measure has been consistently accepted in recent Commission decisions.[449]

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[444] Ex. 76, Griffing Surrebuttal at 15.
[445] Ex. 21, Hevert Direct at 11.
[446] Ex. 59, Smith Direct at 17-18.
[447] Ex. 21, Hevert Direct at 17.
[448] The Constant Growth DCF model is expressed as follows:

$$k = \frac{D(1+g)}{P} + g$$

where "k" equals the required return, "D" is the current dividend, "g" is the expected growth rate, and "P" represents the subject company's stock price. Ex. 21, Hevert Direct at 17; Ex. 73, Griffing Direct at 8.
[449] *See, e.g.,Docket 07-1187,* Findings of Fact, Conclusions of Law, and Order at 57-58; *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for*

387. OES and, in rebuttal, OTP, both used a 30-calendar day averaging period for the purpose of calculating the dividend yield component of the DCF model.[450]

388. In addition, both OTP and OES adjusted their DCF results by 3.984 percent (or 20 basis points) for flotation costs, which reflect the fees and expenses a company must pay in connection with issuing equity. This is the average of actual flotation costs for OTP in connection with stock issuances in 2004 and 2008. These parties agree that the adjustment is appropriate even if no new stock issuance is planned for the test year.

389. The OAG recommended denial of OTP's recovery of flotation costs on the basis that OTC had no plans to issue common stock during the 2010 timeframe. It characterized as "unbelievable" the claim that flotation cost is compensation for previous equity issuances.[451]

390. Flotation costs are a part of a company's permanent equity capital.[452] They are incurred when a company sells new shares of common stock and are accounted for on the balance sheet as a part of paid-in capital.[453] Common stock is closely analogous to long-term debt because, like long-term debt, the primary purpose of both is to provide financing for long-term investments, and both remain part of the utility's balance sheet for long periods. Accordingly, flotation costs and long-term debt issuance costs are parts of the utility's costs in succeeding years.[454]

391. The Commission has allowed recovery of flotation costs when the calculation is done appropriately and when there is evidence of actual cost and a need to raise capital in the future.[455]

392. OTP had capital expenditures averaging $149 million per year between 2007 and 2009, and its capital expenditure plan for 2010 through 2014 will require investment of $128 million per year, on average.[456]

393. OES and OTP used the same method of calculating flotation cost.[457] Their calculation is appropriate and consistent with previous Commission decisions.

394. OES did not include the DCF results for Edison International in recommending ROE, because the results were an extreme low statistical outlier; OTP

Electric Service in Minnesota, Docket No. E-001/GR-08-1065, Findings of Fact, Conclusions of Law, and Order at 8-12 (Oct. 23, 2009).

[450] Ex. 73, Griffing Direct at 22; Ex. 22, Hevert Rebuttal at 14.

[451] Ex. 22, Hevert Rebuttal at 25-26.

[452] Ex. 21, Hevert Direct at 22.

[453] *Id*. at 22.

[454] Ex. 22, Hevert Rebuttal at 22.

[455] *In the Matter of the Petition of Great Plains Natural Gas Company*, Docket No. G-004/GR-04-1487, Findings of Fact, Conclusions of Law, and Order at 10-12 (May 1, 2006); *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates*, Docket No. E-002/GR-05-1428, Findings of Fact, Conclusions of Law and Order at 27 (Sep. 1, 2006).

[456] Ex. 14, Brause Direct at 13-14.

[457] Ex. 21, Hevert Direct at 25; Ex. 73, Griffing Direct at 26.

agreed that Edison International's results should be excluded. OES also excluded the DCF results for Great Plains Energy (14.97%) because the results were a high statistical outlier, more than half a standard deviation above the next-highest ROE of 13.43% for Empire District Electric.[458] OTP included Great Plains Energy in its DCF analysis.

395. Using the DCF method, but excluding the two companies identified above, OES obtained an updated mean ROE of 10.74 percent, with a range of 9.77 percent to 11.78 percent. OES recommended that the Commission use the mean ROE of 10.74 percent for OTP, which translates to an ROR of 8.62 percent.[459]

396. By using the DCF method and including the results for Great Plains Energy, OTP obtained an updated mean ROE of 11.58 percent and a range of 9.69 percent to 13.14 percent.[460] OTP recommended that the Commission use an ROE of 11.25 percent.

397. OTP also combined the OTP and OES groups and calculated a mean ROE of 10.97 percent with a range of 9.29 percent to 12.46 percent.[461] It suggests these results support its recommendation to use an ROE of 11.25 percent.

398. OTP recommended that, in determining where within the range to place OTP, its plans for extensive capital investment, lack of customer diversity, and relatively small size in relation to the comparable group should be considered.

399. OES contends that these risks are already factored into the analysis through reliance on S&P credit ratings to screen the comparable companies, and there is no need to account for them separately. It contends that selecting an ROE on this basis would inappropriately double-count these factors.[462]

400. The Company disagrees that credit rating necessarily reflects the risk to equity holders, as opposed to creditors. It contends that equity investors bear the residual risk after creditors.[463] OTP's BBB- credit rating is below the average rating of OTP's Proxy Group, the average rating of the OES group, and the average rating of the combined group. Because OTP's credit risk is higher than the average of any of these groups, the Company contends that credit rating should be considered when determining where the cost of equity lies within the range of DCF results.[464]

401. OES maintains that in selecting an appropriate ROE, no specific (upward) consideration should be given to OTP's credit rating as compared to the average of the comparable groups. OES pointed out that the ROE it has recommended gave no

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[458] Ex. 76, Griffing Surrebuttal at 8-11.
[459] *Id*. at 12.
[460] Ex. 22, Hevert Rebuttal at RBH-2, Schedule 1, page 1 of 3.
[461] Ex. 22, Hevert Rebuttal at RBH-2, Schedule 1, page 3 of 3.
[462] Ex. 76, Griffing Surrebuttal at 17.
[463] Ex. 22, Hevert Rebuttal at 16.
[464] *Id*. at 17.

specific (downward) consideration to the fact that OTP's equity ratio is higher, and it has less debt, than the average of the comparable groups.[465]

402. The Administrative Law Judge concludes that OES has established that its comparison group is more reasonably reflective of the investment risk of OTP. The Company's proposal is unduly influenced by the inclusion of Great Plains Energy in its comparison group, and as a result the Company's DCF analyses produce unreasonable results. The Administrative Law Judge recommends that the Commission adopt the ROE proposed by OES: 10.74 percent, which produces an ROR of 8.62 percent.

3. Conclusion.

The ROE to be used to determine the cost of service in this proceeding should be 10.74 percent, with a resulting ROR of 8.62 percent as follows (subject to a possible adjustment to reflect a 2.85 percent interest rate on variable rate debt):

	Amount	Percent of Total	Cost	Weighted Cost
Long-Term Debt	$288,367,295	45.50%	6.69%	3.04%
Short-Term Debt	$17,956,893	2.80%	0.79%	0.02%
Common Equity	$328,112,867	51.70%	10.74%	5.55%
Total		100.0%		8.62%

X. RATE DESIGN ISSUES.

403. Rate design, in contrast to the determination of the revenue requirement, is largely a quasi-legislative function. It involves establishment of the utility's rate structure, such as deciding in what proportions the revenue requirement will be recovered from each customer class. This step of rate making largely involves policy decisions to be made by the Commission.[466]

404. The Commission has historically considered a variety of cost and non-cost factors when designing rates. In addition to the results of the CCOSS, the Commission considers other factors, including economic efficiency; continuity with prior rates; ease of understanding; ease of administration; promotion of conservation; ability to pay; and ability to bear, deflect, or otherwise compensate for additional costs.[467]

A. Class Revenue Apportionment.

405. In this case, OTP proposed a class apportionment of its total base rate revenue responsibilities among its rate classes primarily based on its CCOSS.[468] OTP was also guided in its class apportionment proposal by its rate design objectives,

[465] Ex. 76, Griffing Surrebuttal at 19.
[466] *St. Paul Area Chamber of Commerce v. Minnesota Public Service Commission*, 312 Minn. 250, 260, 251 N.W.2d 350, 357 (1977)
[467] *Id*.
[468] Ex. 34, Beithon Direct at 70-75.

including the objectives of maintaining reasonable rate continuity, mitigating rate shock, and encouraging efficient use of resources.[469]

406. The OES agreed that OTP's class revenue apportionment proposal is reasonable and should be approved.[470] Those class revenue allocation percentages, inclusive of the rolled-in renewable project costs, are reflected in the following table:

OES Revised Revenue Apportionment
Including Wind Facility Recovery in Base Rates[471]

Customer Class	OTP Total Current + RRA Revenue	Total Revised CCOSS + Wind CCOSS	OTP Proposed Apportionment	% of Total	% Chg.	OES Proposed Revenue Apport.	% Change from Current
Residential	$41,059,416	$50,069,091	$46,967,680	28.9%	14.4%	$41,581,913	1.3%
Farm Service	$2,752,105	$3,188,734	$6,252,149	2.0%	18.2%	$2,879,226	4.6%
Gen. Service	$28,279,782	$28,764,133	$30,698,956	18.9%	8.2%	$27,178,718	-3.9%
Large Gen. Service	$60,462,295	$62,253,965	$66,722,284	41.0%	10.4%	$59,071,264	-2.3%
Irrigation	$256,965	$515,069	$318,924	0.2%	24.1%	$282,353	9.9%
Lighting	$2,514,485	$2,978,484	$2,941,927	1.8%	17.0%	$2,604,577	3.6%
OPA	$1,255,824	$1,488,292	$1,450,173	0.9%	15.5%	$1,283,882	2.2%
Controlled Water Heat	$1,457,627	$2,563,716	$1,860,430	1.1%	27.6%	$1,647,095	13.0%
Interruptible	$5,476,363	$9,291,079	$6,963,954	4.3%	27.2%	$6,165,400	12.6%
Deferred Load	$1,232,226	$1,452,850	$1,388,935	0.9%	12.7%	$1,229,667	-0.2%
Total	**$144,744,088**	**$162,565,413**	**$162,565,413**	**100.0%**	**12.3%**	**$143,924,095**	**-0.6%**

407. Using the revenue allocation above, all customer classes that are currently apportioned revenue responsibility that is over cost (General Service and Large General Service) would receive small decreases in revenue responsibility, while the remaining classes would be moved closer to cost.[472]

408. The MCC argues that the revenue allocations to the LGS class should be reduced by half, as the proposed revenue apportionment does not, from the MCC's perspective, adequately mitigate interclass subsidies.[473] The MCC's proposal would reduce the LGS class's apportionment and increase the apportionment to all other classes.

[469] Ex. 34, Beithon Direct at 70-75.
[470] Ex. 83, Peirce Surrebuttal at 2-3.
[471] "Current" includes recovery of costs both in base rates and OTP's RRA. *See* Ex. 83, Peirce Revised Surrebuttal at 10. The "% of Total" column is the agreed-upon allocation to the classes.
[472] Ex. 83, Peirce Revised Surrebuttal at 10.
[473] MCC Initial Brief at 18-20; MCC Proposed Findings at 5.

409. The MCC also argues that the proposed revenue apportionment does not adequately consider that renewable and other rider-related increases that have occurred since OTP's last general rate case have fallen disproportionately to the LGS class because rider mechanisms are typically based on energy sales.[474]

410. Not all riders, however, are based on energy. OTP's transmission rider is allocated based on demand, not energy. In addition, renewable rider projects have produced energy that has been reflected in OTP's fuel clause adjustment (FCA) at zero cost, and therefore the energy produced by the projects has reduced OTP's cost of energy. The impact of these reduced energy costs was one of the reasons OTP was able to reduce its costs of energy by approximately 10 percent when it reset its base cost of energy at the commencement of this case. The MCC has not established that it would be appropriate to alter the above-referenced revenue apportionment due to rider cost recoveries that have been implemented since the Company's last general rate case.

411. The record in this case demonstrates that the above-referenced apportionment to the classes agreed to by OTP and the OES appropriately reduces class subsidies and balances other policy considerations to arrive at a fair and reasonable revenue apportionment.

B. Residential Customer Charge.

412. In OTP's last rate case, it increased the customer charge from $6.15 in urban areas and $7.15 in rural areas to a single customer charge of $8.00 per month.[475] In this case, OTP proposes to increase the residential service customer charge to $9.00, based on its marginal cost study showing residential customer costs are $12.19 per month.[476]

413. The OES agreed that some increase in the customer charge is necessary to minimize the effects of intra-class subsidies. OES proposes a more moderate increase of the charge to $8.50, which would move the charge to 70 percent of the monthly marginal cost.[477]

414. Given that the last increase in the customer charge was only recently implemented, the Administrative Law Judge agrees that moving this charge to $8.50 is a sufficient movement toward cost. The Administrative Law Judge recommends that the Commission adopt the OES proposal and set the residential customer charge at $8.50.

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[474] Ex. 115.
[475] *Docket 07-1187*, ALJ Findings of Fact, Conclusions, and Recommendation at ¶¶ 442-450.
[476] Ex. 42, Prazak Rebuttal at 3.
[477] Ex. 81, Peirce Direct at 11.

C. LGS and LGS TOD Rate Design.

415. OTP proposed to continue with the current LGS and LGS time of day (TOD) rate design, but to adjust rate levels and make minor language changes.[478] It set the energy and demand charges for these rates based on its 2010 Marginal Cost Study, adjusted to match the proposed revenue requirement in a manner that retains the benefits of marginal cost price signals.[479] This resulted in a decrease in on-peak energy rates, and an increase in off-peak prices.

416. The OES recommended approval of the LGS tariffs as proposed.[480]

417. The MCC and Enbridge proposed to increase demand charges in the LGS service beyond the charges included in OTP's proposal; set the LGS TOD firm-service demand charge equal to the LGS demand charge; and maintain the current LGS TOD off-peak energy charge. The MCC argues that while the firm-service demand charges in OTP's proposed LGS rate have increased, the charges still are too low and will cause LGS customers taking interruptible service to shift to firm service and will discourage the addition of new interruptible load.[481] Enbridge contends that LGS TOD customers have changed operation based on the price signals established in the last rate case and that the changes to on-peak rates will provide a disincentive to shift energy use to off-peak periods.[482]

418. With regard to the recommended increase in demand charges, OTP pointed out that a further increase in the demand charge would result in lower energy charges, which would shift costs from large energy-use customers to smaller energy-use customers within the LGS class. It would also create cross-subsidies within the LGS class—meaning one group of customers would pay more than it should for its service to help pay for the cost to serve another group of customers.[483]

419. In addition, OTP established that the LGS and LGS TOD rates do not have the same time-differentiated demand costs. Both rates begin with the same marginal demand costs, but, by design, each schedule results in a different demand charge. The LGS demand charge is based on the seasonal marginal demand costs measured across all hours in each season. The LGS TOD is based on the probability of peak seasonal demand costs during the time-differentiated hours (peak, shoulder, and off-peak) across each season. If the LGS TOD on-, shoulder- and off-peak demand charges are summed – they are essentially the same as the LGS TOD demand charges. This reflects that the demand charges in the two rate options are comparable and reasonable.[484]

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[478] Ex. 40, Prazak Direct at 31-35.
[479] *Id*.
[480] Ex. 81, Peirce Direct at 18.
[481] Ex. 57, Schedin Direct at 23-26.
[482] Ex. 53, Erickson Direct at 25.
[483] Ex. 42, Prazak Rebuttal at 7-8.
[484] *Id*.

420. OTP pointed out that the interruptible riders continue to reflect substantial incentives, but argued that the rider rates should not arbitrarily disregard the marginal costs of service.[485]

421. The MCC also proposes that OTP should be required to establish a load factor credit for the LGS TOD rate. MCC proposes implementing the credit when energy use reaches a "breakeven point" of about 360 hours or on any use over a load factor of about 50 percent, at which point customers would see a reduction in the energy charge. The MCC bases this proposal on a high load factor credit used by Xcel Energy.[486]

422. The MCC's proposed load factor credit is similar to a declining load factor block rate. Both the block rate and the credit serve to reduce the cost of energy as a customer's energy consumption increases. In OTP's last rate case, the Commission required the Company to eliminate all declining rate structures on the basis that they conflict with statutory directives to encourage economically efficient energy use and prevent customers from receiving necessary price signals.[487] It would be inconsistent with Commission policy to establish a rate that reduces the cost of energy as energy consumption increases.

423. Enbridge contended that, because the marginal cost study OTP used in its last rate case did not accurately predict the subsequent precipitous drop in energy market prices, the differential between demand and energy prices set in the last case should be retained in the interests of providing certainty for LGS customers who have made operational changes based on the previous rates.[488]

424. MCC argues that the generation portion of OTP's marginal cost study should have reflected the future cost of OTP's next planned generation resource—a gas turbine—instead of market demand costs.[489] The MCC made the same basic argument in OTP's last rate case, at that time arguing that marginal demand costs should have been based on the costs of the Big Stone II project, which was OTP's next planned generating resource at that time. The Commission rejected this argument as follows:

> The Commission also accepts Otter Tail's use of market prices as the basis for its marginal capacity costs. The Company's rates should not be altered to reflect anticipated capacity costs, such as those associated with the proposed Big Stone II facility.[490]

425. The Company has established that it appropriately based its energy and demand charges and its on- and off-peak rates on the marginal cost study. The

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[485] Ex. 42, Prazak Rebuttal at 7-8.
[486] Ex. 57, Schedin Direct at 26.
[487] *Docket 07-1187* Order at 71-72.
[488] Ex. 55, Erickson Surrebuttal at 26-27.
[489] Ex. 58, Schedin Surrebuttal at 11.
[490] *Docket 07-1187* Order at 64.

Administrative Law Judge recommends that the Commission accept the proposed LGS and LGS TOD rate design.

XI. RESOLVED AND UNCONTESTED ISSUES.

A. Advertising Expense.

426. OTP included advertising expenses of $211,375 in the test year for the Minnesota jurisdiction.[491] The OES recommended disallowing $2,913 in expense for certain advertisements that appeared to promote goodwill or improve the Company's image instead of promoting electrical safety, and for other advertisements that in its view encouraged customers to add an electric heating source to an existing fossil fuel heating system, promoting growth in electric sales.[492] In making its proposed adjustment, OES used some Minnesota-only numbers and some system-wide numbers.

427. Although it maintained that its advertisements for dual fuel systems are appropriately recoverable as promoting demand-side management goals, OTP agreed to the proposed adjustments for the advertisements, and it recalculated the amounts using the correct numbers.[493] The Company's total adjustment for advertising, system-wide, is $4,409. The adjustment on a Minnesota jurisdictional basis is a reduction of $2,095 to test year advertising expense.[494]

B. Amortization of MISO Schedule 16 and 17 Costs.

428. During the course of creating the adjustments for the test year, OTP assumed that the amount of MISO Schedule 16 and 17 costs being amortized were system-wide costs; however, the amount that was actually being booked by OTP's Accounting Department was the specific jurisdictional amount for both Minnesota and North Dakota. OTP removed $292,895 for the amortization of MISO Schedules 16 and 17 costs, but should have removed only $152,979 based on the amount the OTP Accounting Department had recorded.

429. The OES accepted OTP's correction for the difference between these two numbers, or an increase of $139,916 to expenses.[495]

C. Ancillary Services Market (ASM).

430. Ancillary services are support services required to balance generation and load across the entire MISO system, within the operating parameters required to maintain the reliability and security of the grid and the quality of power it delivers. In 2009, MISO began operating an ancillary services market (ASM), where utilities can buy or sell ancillary services on a wholesale basis. The Company proposed to pass through

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[491] Ex. 4, Volume 3, PJB-1, Schedule G-1 at 2.
[492] Ex. 70, Davis Direct at 8-10.
[493] Ex. 36, Beithon Rebuttal at 62-63.
[494] *Id*.
[495] Ex. 36, Beithon Rebuttal at 45-46, Ex. 104, Campbell Surrebuttal at 7.

2009 ASM net revenues ($138,900) through the fuel adjustment clause.[496] In response to OES information request 117 (which requested OTP's 2005 to 2009 asset-based margin information), OTP found that it had not removed the 2009 ASM margin of $138,973 from the test year. Removing the 2009 ASM margins increases the revenue requirement by $138,973.[497]

431. The OES and the Company are in agreement that OTP's ASM revenues and expenses should flow through the FCA and that test year revenues should be increased to compensate for the removal of the 2009 ASM margin of $138,973.[498]

D. Asset-Based Margins.

432. In OTP's last rate case, the Commission used a fixed $5.41 million credit to the base rate revenue requirement for asset-based margins. The number was derived using a four-year average.[499] In its Order, the Commission stated:

> [T]he Commission acknowledges Otter Tail's concern that its margins in the early years of the Day 2 market have been regressing toward pre- Day 2 levels, and may prove to be unrepresentative.
>
> Faced with this uncertainty, the Commission will select an intermediate course. The Commission will estimate Otter Tail's future asset-based wholesale margins based on an average of the margins Otter Tail earned over the past four years. …
>
> In sum, the Commission will set Otter Tail's base rates on the assumption that Otter Tail's costs are offset by $5.41 million in revenues from Otter Tail's asset-based wholesale margins.[500]

433. Since that time, reductions in market energy prices have resulted in significantly reduced asset-based wholesale margins. OTP's asset-based margins have dropped to $1,518,119 actually earned in 2009.[501] This drop amounts to a revenue deficiency of $3,891,881.[502]

434. Because of the difficulty involved in accurately estimating asset-based margins for purposes of a fixed credit, OTP proposed in this case to move the credit from the base rate revenue requirement to the FCA revenue requirement.[503] This is consistent with the Commission's recent treatment of asset-based margins in Xcel

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[496] The ASM revenue is reported pursuant to the Commission's Order in Docket No. E-001, E-015, E-002, E-017/M-08-528. *See* Ex. 34, Beithon Direct at 23-24.
[497] Ex. 36, Beithon Rebuttal at 11-13.
[498] Ex.104, Campbell Surrebuttal at 4-5.
[499] *Docket 07-1187* Order at 26.
[500] *Id*.
[501] Ex. 14, Brause Direct at 8.
[502] *Id*.
[503] *Id*. at 9-10.

Energy's 2008 rate case.[504] This treatment would ensure accuracy of the credit for both customers and OTP, in that customers receive the full value of asset-based wholesale margins, and OTP would not experience over- or under- recoveries when changes to margins occur.[505] Moreover, there would be no lag between a change in asset-based margins and the credit passed through to customers.[506] In addition, with an FCA mechanism, as wholesale prices vary, the variations in the margin credit will correspond to similar variations in purchase power costs flowing through the FCA.[507]

435. OTP also proposed passing all ancillary service market (ASM) costs and revenues through the fuel clause.[508] Matching the asset-based wholesale margin crediting mechanism and ASM mechanism would avoid unnecessary complications in the allocation of costs and revenues between these activities. Putting all retail and asset-based wholesale energy and ancillary service costs and revenues in a single mechanism would simplify the process of changing the allocation of those costs and revenues between retail and wholesale activities, as the Commission deems appropriate.[509]

436. The MCC agreed that OTP's proposed FCA crediting mechanism for actual margins should be used.[510]

437. The OES initially recommended that the Commission use a fixed credit for wholesale asset-based margins, rather than the flowing the credit through the FCA.[511] At the evidentiary hearing, however, OES agreed to accept OTP's proposal for a flow-through wholesale asset-based margin mechanism with appropriate reporting requirements, in conjunction with OTP agreeing with the OES proposal to roll recovery of wind facilities from the rider into base rates using the numbers proposed by OES for this recovery.[512]

438. Accordingly, the parties are in agreement with OTP's proposal to move the credit for asset-based margins from base rates to the FCA revenue requirement.

E. Association Dues.

439. OTP proposed to include $104,540 in association dues in the test year.[513] The OES found this expense consistent with Commission policy and recommended that

[504] I*n the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-002/GR-08-1065.
[505] Ex. 14, Brause Direct at 10.
[506] *Id*.
[507] *Id*.
[508] *Id*.
[509] Ex. 14, Brause Direct at 10.
[510] Ex. 57, Schedin Direct at 19-20.
[511] Ex. 98, Campbell Direct at 15.
[512] Ex. 108, Campbell Summary Statement.
[513] Ex. 24, Beithon Direct at 66; *see also* Ex. 4, Volume 3, PJB-1, Schedule G-3.

the Commission approve it.[514] The OAG's objections to some of these expenses are addressed in Finding Nos. 288-96.

F. Cash Working Capital.

440. There is no dispute concerning the methodology used by the Company for cash working capital.[515] OTP and the OES agree that cash working capital in rate base will need to be recalculated to reflect Commission approved financial adjustments.[516]

G. Charitable Contributions.

441. OTP included $96,752 in the revenue requirement as charitable contribution expense, or 50 percent of its actual expense in the test year.[517] This is the amount allowable under Minn. Stat. §§ 290.21, subd. 3(b) and 216B.16, subd. 9. In response to the Commission's Statement of Policy on Charitable Contributions, OTP provided an itemized list showing the amount, recipient, and date of the 2009 donations made in Minnesota.[518] The OES agreed that OTP's proposed charitable contribution expenses are reasonable.[519] The issue whether administrative costs of making charitable contributions should be removed from the test year is separately discussed.[520]

H. Conservation Improvement Plan (CIP).

442. There were three issues involving the CIP: (1) The correct amount of CIP expenses to include in the test year, and how much of those expenses should be recovered in base rates through the conservation cost recovery charge (the CCRC); (2) the proper method for allocating those costs to the customer classes in the rate case; and (3) the proper method for allocating costs recovered through the conservation cost recovery adjustment (CCRA).

443. OTP included $2,733,372 of CIP expense in its test year. The Company had collected $1,783,371 of the expense from the CCRC included in base rates and the remaining $950,001 was collected through the CCRA.[521] Test year CIP revenues and costs were not adjusted and included only approved program costs and corresponding offsetting revenues.[522] OTP did not propose any changes in the method of recovery under the CIP Rider in this rate case, as it believes it would be more appropriate to make any changes in its next annual CIP incentive filing.[523]

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[514] Ex. 70, Davis Direct at 17.
[515] Ex. 36, Beithon Rebuttal at 63.
[516] Ex. 25, Sem Rebuttal at 8; Ex. 110, Lusti Direct at 15.
[517] Ex. 34, Beithon Direct at 65-66.
[518] *Id*. at 66.
[519] Ex. 70, Davis Direct at 16.
[520] *See* Finding Nos. 273-76.
[521] Ex. 34, Beithon Direct at 33.
[522] *Id*.
[523] *Id*.

444. The OES proposed that the revenue requirement should reflect the most recently approved CIP budget of $3,670,200 and that the full amount should be recovered in base rates through the CCRC.[524] OES proposed increasing CIP expense by $1,904,800 ($3,670,200 - $1,765,400).[525] The OES noted that, while this change would increase base rates, the amount recovered from OTP customers for CIP expenses should not change overall because the extra expense would not be collected through the CCRA adjustment.[526]

445. OTP concurred that the revenue requirement should reflect the most recent CIP budget of $3,670,200 and that it should be recovered through the CCRC, a change that would be revenue neutral. OTP corrected the increase to the base rates to $936,828 ($3,670,200 minus $2,733,372), which accounts for the total amount of CIP expense included in OTP's initial filing.[527] The OES agreed with OTP's adjustment of $936,828.[528]

446. OTP also proposed to use the E8760 allocator to allocate CIP expenses in the rate case, instead of using a cost per kWh. The OES and the MCC supported using the E8760 allocator for this purpose in this proceeding.[529] OTP did a comparison of the E2 allocator versus the E8760 allocator in response to OES IR 704, if the Commission is interested in examining the differences between the two methods.[530]

I. Current Rate Case Expense.

447. The Company sought recovery of $1,485,236 in expenses for the current rate case, to be amortized over three years.[531] The OES did not challenge the Company's estimated rate case expense of $1,485,236 but recommended allowing use of a three-year amortization period with the condition that the Commission require the Company to establish a deferral account for rate-case expenses recovered beyond the three-year period. OES further recommended that if the Company's next rate case occurs after having recovered its rate-case expense, then the Company should defer $41,257 per month and credit this amount to offset its revenue requirement in its next rate case.[532]

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[524] Ex. 70, Davis Direct at 12-13.
[525] *Id*.
[526] *Id*.
[527] Ex. 36, Beithon Rebuttal at 37.
[528] Ex. 72, Davis Surrebuttal at 2.
[529] Ex. 70, Davis Direct at 15; Ex. 58, Schedin Surrebuttal at 1. In another pending docket, the Chamber has proposed using separate allocators for avoided energy and avoided demand costs. *See* Docket No. E017/M-10-220. The OES analysis of the Chamber's proposal in that docket is not yet complete.
[530] Ex. 70, Davis Direct at 15.
[531] Ex. 34, Beithon Direct at 59.
[532] Ex. 96, La Plante Direct at 10.

448. OTP agreed that any over-recovery of rate case expenses would be deferred at a rate of $41,257 per month and offset from the revenue requirement in the next rate case.[533]

J. Customer Factor.

449. During discovery, the Company identified an error in the calculation of its customer factors. In response to Enbridge Information Request 139, OTP provided the corrected data, which reduced the Minnesota jurisdictional impact by $180,344.[534] Enbridge acknowledged the correction in Rebuttal Testimony.[535]

K. Economic Development Expense.

450. In its last rate case, the Company was allowed to recover half of its economic development costs in Minnesota. In 2009, OTP spent a total of $172,195, one-half of which is $86,097. The Company sought recovery of $86,097 in economic development expense.[536]

451. The OES concluded that the Company used the appropriate types of benefits and costs in its ratepayer impact analysis. It recommended approval of OTP's proposed economic development expense in the amount of $86,097.[537]

L. FCA Rider Amendments.

452. **Energy Adjustment Rider.** The OES recommended that OTP change the language of its proposed FCA Rider from:

> … and all expenses incurred by the Company pursuant to Minnesota Statutes, Section 216B.1645, except any such expense identified in 216B.1645, subd. 1(1)

to:

> … and all fuel and purchased energy expenses incurred by the Company over the duration of any Commission-approved contract, as provided for by Minnesota Statutes, Section 216B.1645, except any such expense identified in 216B.1645, subd. 1(1), and subd. 1(2) to satisfy the renewable energy obligations set forth in Minnesota Statutes, Section 216B.1691.[538]

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[533] Ex. 36, Beithon Rebuttal at 62.
[534] *Id*. at 42; *see also* Ex. 36 at PJB-2, Schedule 2, for a summary of the revenue deficiency and required increase before and after this correction plus the revised JCOSS and CCOSS; and Ex. 36 at PJB-2, Schedule 3, for a copy of the response to IR EE-139.
[535] Ex. 54, Erickson Rebuttal at 4.
[536] Ex. 34, Beithon Direct at 53.
[537] Ex. 70, Davis Direct at 4.
[538] Ex. 77, Ouanes Direct at 22.

453. OTP concurs with this clarification.[539]

454. **MISO Costs and Revenues.** OTP proposed to amend the language of the energy adjustment rider related to MISO costs passed through the rider. A new paragraph 4 was added for clarity on MISO costs:

> All Midwest ISO (MISO) costs and revenues associated with retail sales that have been authorized by the Commission to flow through this Energy Adjustment Rider and excluding MISO costs and revenues that are recoverable in base rates, as prescribed in applicable Commission Orders.[540]

455. OES agreed that the language was reasonable since it ensured that: (1) only costs of serving retail customers would be charged to retail customers; (2) both costs and revenues were included; (3) costs and revenues already recovered in base rates were not double-counted in the FCA; and (4) the Commission's Orders were reflected on an ongoing basis. Further, the proposed language is consistent with language in other utility tariffs.[541]

456. **MISO Control Area Service Operations (CASOT).** OTP also added the following paragraph 8 to address recovery of asset-based margins and ASM costs and revenues through the Energy Adjustment Rider:

> Less a credit for asset-based margins: revenues minus costs from asset-based wholesale energy and MISO ancillary services market (ASM) transactions (excluding ancillary services revenues derived through OTP's FERC-approved Control Area Services Operations Tariff) shall be credited to the cost of energy. The revenues for this calculation are those received from sales of excess generation; the costs are the fuel costs (as defined in FERC Account 501) and energy costs (including MISO costs that are booked to FERC Account 555) and any transmission costs incurred that are required to make such sales.[542]

457. OES agreed that the CASOT revenues were been included in the test year under Other Electric Revenues and that the expenses were embedded in the production costs. Therefore, it accepted the proposed language with one correction to paragraph 8: "(excluding ancillary service net revenues derived through OTP's FERC-approved Control Area Services Operation Tariff)" with "net revenues" defined to mean revenues less expenses.[543] OTP accepts that amendment to paragraph 8. The OES and OTP consider these issues resolved.[544]

[539] Ex. 42, Prazak Rebuttal at 2.
[540] Ex. 34, Beithon Direct at 24.
[541] Ex. 98, Campbell Direct at 16-17.
[542] Ex. 34, Beithon Direct at 24.
[543] Ex. 108, Campbell Evidentiary Hearing Summary Statement at 1.
[544] OES Initial Brief at 127.

M. Farm Service Tariff.

458. In its Initial Filing, OTP proposed restructuring its Farm Service tariff to include a $12 per month customer charge and to eliminate the difference between its overhead and underground facilities charge for 3-phase service, implementing a flat $8 facilities charge.[545] Currently, there is a $20 monthly minimum bill, but no customer charge.[546] The OES noted that the proposed $12 monthly customer charge and the $8 monthly facilities charge would have no impact on the monthly minimum billing for a typical farm service customer. The OES recommended approval of the Farm Service tariff.[547]

N. General Service Tariff Changes.

459. **Small General Service Customer Charge.** OTP proposed to increase the customer charges as follows: Small General Service customers using less than 20 kW from $15.00 to $15.50 per month; Small General Service customers using more than 20 kW from $18.50 to $19.00 per month, and Small General Service Time-of-Use customers from $5.00 to $19.00 per month.[548]

460. The OES initially considered that the customer charge for Small General Service customers using more than 20 kW should be increased to $19.50 per month, to align more closely with the marginal cost of service and reduce intra-class subsidies. After reviewing OTP's summary of bill impacts for these customers, however, OES concluded that OTP's proposed increase to this category of customers would result in a less burdensome increase for the lower usage customers. The OES recommended approval of OTP's proposed customer charges for its Small General Service customers.[549]

461. **Phasing Out Small General Service Rate Codes.** OTP proposed to cancel rate codes 30-406 and 30-407, both of which are offered under OTP's General Service Under 20 kW, Section 10.01. These two rate codes offer non-metered service under 20 kW for both secondary and primary service customers. No customers are impacted by this change.[550] The OES recommended approval of the proposed cancellation.[551]

462. OTP proposed to phase out rate code 30-408 over time, with the first step to be closing this rate to new installations in this rate case. Rate code 30-408 is offered under OTP's General Service Under 20 kW, Section 10.01. This non-metered service of 1,000 watts or less is offered under this rate code. The equipment currently being served on this rate consists of cable TV amplifiers, telephone company phone booths,

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[545] Ex. 40, Prazak Direct at 22.
[546] *Id*.
[547] Ex. 81, Peirce Direct at 15; *see also* OES Initial Brief at 136.
[548] Ex. 40, Prazak Direct at 22-30.
[549] Ex. 81, Peirce Direct at 16.
[550] Ex. 40, Prazak Direct at 67-68.
[551] Ex. 81, Peirce Direct at 17.

traffic signal and sign lighting customers that required 24 hour per day service. OTP currently has 12 customers on this rate, who would be allowed to continue to receive service on this rate until a change in service requires the installation of metering equipment.[552] The OES recommended approval.[553]

463. **Terms and Conditions Changes to General Service Tariff.** The OES summarized OTP's proposed changes to its General Service tariff as follows: (1) remove the requirement that customers sign an electric service agreement; (2) include Residential three-phase service under the tariff's applicability; (3) add seasonal service; (4) add clarifying language covering when a customer will be moved from the Small General Service < 20 kW and Small General Service > 20 kW tariffs; and (5) standardize the facilities charge for General Service Time-of-Use customers.[554] The OES concluded that the proposed changes would streamline service, move charges closer to cost, and make service offerings clearer to customers. Therefore, the OES recommended approval of these proposed tariff changes.[555]

O. Group Insurance.

464. In its Initial Filing, OTP included $9,810,980 in total company expense for its Group Insurance, described as including active medical, dental, life insurance, and long-term disability insurance.[556] During the course of this proceeding, OTP updated its system-wide medical expense forecast, which reduced the amount for its Group Insurance to $9,399,842.[557] The net result is a reduction of $171,084 for the Minnesota jurisdiction.[558]

465. The OES recommended against OTP's two-step approach of first removing amounts related to "construction labor" and then applying the 49.1292% Minnesota jurisdictional allocator to the balance. The OES instead applied the allocator without removing those costs, which resulted in a $201,989 adjustment.[559]

466. OTP agreed with the OES's reduction; however, it noted that the net decrease should be $259,612 (total company) based on the updated costs and the exclusion of the construction labor costs.[560] Mr. Beithon showed the calculation to reflect the adjustment to the Medical and Dental costs, less the exclusion for capitalization and non-utility allocation, and the allocation to the Minnesota Jurisdiction

[552] Ex. 40, Prazak Direct at 68-69.
[553] Ex. 81, Peirce Direct at 17.
[554] *Id*.
[555] *Id*.
[556] Ex. 26, Wasberg Direct at 19.
[557] Ex. 98, Campbell Direct at 52; *see also* Ex. 100, Campbell Direct Attachment NAC-16.
[558] *Id*. at 53; *see also* Ex. 100, Campbell Direct Attachment NAC-17.
[559] *Id*. at 54.
[560] Ex. 29, Wasberg Rebuttal at 21.

for a revised adjustment of $127,350 decrease in Medical and Dental expenses.[561] The OES agreed with the Company regarding these adjustments.[562]

P. High Voltage Test Lab.

467. Fourteen years ago, in Docket No. E-017/PA-97-697, the Commission approved the sale of the Company's high voltage test lab, but required the Company to continue to impute revenues from the business.[563] In its initial filing in this case, OTP made an adjustment to decrease the test year revenue in the amount of $96,768, reversing a 2009 imputed revenue credit from the sale of the high voltage test lab.[564]

468. The OES noted that the language of the Commission's Order Modifying Settlement, dated October 17, 1997, stated that the Company must impute income from the high voltage test lab "for a minimum of ten years from the date of filing of Otter Tail's next rate case."[565] The Company filed its first rate case after Docket No. E-017/PA-97-697 on October 1, 2007.[566] Therefore, OES noted that the earliest date on which the Company was entitled to stop imputing income from the high voltage test lab is October 1, 2017.[567]

469. Although OTP did not agree that it is reasonable to assume that the test lab would continue to provide benefits to ratepayers more than 14 years after its sale, the Company agreed that the OES proposal is consistent with the language of the 1997 Order.[568] The Company also accepted the OES calculation of the adjustment as a $105,444 reduction to the revenue requirement.[569]

Q. Interest Synchronization.

470. The Company calculated its interest-expense deduction for test-year income-tax purposes by multiplying its rate base by the weighted cost of debt, which is 3.08 percent.[570]

471. The OES agreed with the Company's methodology for calculating interest synchronization, finding both the weighted cost of capital used to calculate interest synchronization and the Company's methodology for interest synchronization acceptable.[571] The Company and the OES agree that the interest synchronization adjustment will need to be recalculated when the final rate adjustments approved by the

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[561] Ex. 36, Beithon Rebuttal at 51.
[562] Ex. 105, Campbell Surrebuttal at 8.
[563] Ex. 34, Beithon Direct at 34.
[564] Docket No. E-017/PA-97-697; Ex. 34, Beithon Direct at 34.
[565] Ex. 110, Lusti Direct at 17.
[566] *Docket 07-1187*.
[567] Ex. 110, Lusti Direct at 17.
[568] Ex. 36, Beithon Rebuttal at 61.
[569] *Id*.
[570] Ex. 110, Lusti Direct at 31.
[571] *Id*.

Commission are known.[572] The Company will incorporate the impacts of any adjustments to interest synchronization in its compliance filing in this proceeding.[573]

R. Irrigation.

472. OTP offers customers two rate options for irrigation service: Option 1 is a Non-Time-Of-Use option with a single energy charge; and Option 2 is a Time-of-Use rate structure that includes on-peak, off-peak and intermediate periods.[574] OTP proposed a $1.00 increase in the customer charge for both rate options, thereby raising the charge for Option 1 to $2.00 per month and Option 2 to $6.00 per month.[575] OTP also proposed clarifying language to define Option 2 usage periods more clearly.[576] The OES recommended approval of OTP's proposed changes to its Irrigation tariff because the changes would move the rates closer to costs and make the service more understandable.[577]

S. Key Performance Award.

473. The OTP Key Performance Award (KPA) Plan includes approximately 388 non-union employees.[578] The plan's maximum payout level is 6 percent of the respective individual employee's base salary.[579] The plan includes: (i) four operating criteria (safety, customer satisfaction, equivalent plant availability, and reliability based on the average outage minutes per customer); and (ii) one financial criterion relating to the control of operation and maintenance (O&M) costs.[580] Each of these five criteria has a weighting. The four operating criteria each have a weighting of 1 percent, and the O&M cost criteria has a weighting of up to 2 percent.[581] Payouts under the operating criteria are not financially tied to the O&M criterion.[582]

474. The OAG disputed the calculation for the KPA, believing OTP based the calculation on a 5-year average payout for the KPA that used rounded percentages, instead of actual percentages, causing the test year KPA expense to be overstated by approximately $75,000.[583] The OES did not take exception to OTP's five year average for establishment of the test year KPA expense.[584]

475. In its rebuttal testimony, the Company explained its calculation for the KPA, demonstrating that the rounded percentages were not the basis for the calculation

[572] Ex. 36, Beithon Rebuttal at 64.
[573] *Id*.
[574] Ex 40, Prazak Direct at 39.
[575] *Id*.
[576] *Id*.
[577] Ex. 81, Peirce Direct at 19.
[578] Ex. 26, Wasberg Direct at 7.
[579] *Id*.
[580] *Id*.
[581] *Id*.
[582] *Id*.
[583] Ex. 59, Smith Direct at 39.
[584] Ex. 110, Lusti Direct at 25.

of the KPA expense amount included in OTP's test year in this case.[585] In surrebuttal, the OAG agreed with the Company's calculation and stated that there is "no disputed issue regarding OTP's KPA payout calculation."[586]

T. Large General Service.

476. OTP proposed adding a $40 per month customer charge to the Large General Service (LGS) rate for those customers who continue to use the single block seasonal demand and energy charges. A $60 per month customer charge was proposed for Large General Service Time-of-Day customers. OTP also proposed to add a capacity reservation charge for Standby Service.[587] The OES noted that under the proposed tariff, Large Power Time-of-Day customers would pay a minimum monthly bill of $380 plus a monthly customer charge of $60 plus the facilities charge.[588] In response to MN-IR-OES-308, OTP stated that it is seeking to make its Minnesota minimum monthly rate design consistent with charges in its North and South Dakota jurisdictions. In addition, OTP noted that the $380 minimum was intended to recover some additional customer and facilities costs from customers with minimal energy usage.[589] OES supported OTP's proposal.[590] Further, with respect to the changes to the Standby Service rates, OTP stated it currently has no customers taking Standby Service. OES also recommended approval of these proposed changes to the Large General Service Tariff.[591]

U. Lead Lag Study.

477. The OES and OTP agree that the lead lag study should be refreshed to reflect the final Commission approved adjustments.[592]

V. Lighting.

478. OTP proposes three different changes to lighting tariffs: proportional increased charges for all current lighting fixtures, the addition of a new Metal Halide lighting fixture to replace the old mercury-vapor fixtures, and the cancellation of Sign Lighting Service (Rate Code 747) with the service being moved to the 11.04 Outdoor Lighting – Energy Only Rate (Rate Codes 748-749).[593] The OES recommended approval of the proposed changes to the Lighting tariff.[594]

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[585] Ex. 29, Wasberg Rebuttal at 22-23.
[586] Ex. 67, Smith Surrebuttal at 47.
[587] Ex. 40, Prazak Direct at 31-38.
[588] Ex. 81, Peirce Direct at 18.
[589] *Id*. at Attachment SLP-6.
[590] Ex. 81, Peirce Direct at 18.
[591] *Id*.
[592] Ex. 25, Sem Rebuttal at 7, Ex. 110, Lusti Direct at 15.
[593] Ex. 40, Prazak Direct at 44.
[594] Ex. 81, Peirce Direct at 20.

W. Momentary Average Interruption Frequency Index (MAIFI).

479. The MCC recommended that OTP's LGS customers should have direct access to a Company website that provides momentary outage information on transmission and distribution facilities that serve LGS customers.[595]

480. OTP does not currently offer direct access to momentary outage information to OTP's customers; however, it is working to make interruption information available to all customers on its web site.[596] OTP is willing to work with LGS customers to allow a higher level of access to interruption information on transmission and distribution facilities that serve LGS customers. There is an added cost associated with making a higher level of access to interruption information available to individual customers, and OTP's expectation is that customers requesting a higher level of interruption information would cover those added costs.[597] The additional facilities would be charged to customers under OTP's special facilities provision in the general rules and regulations of OTP's rate book, which is Section 5.03.[598] OTP has agreed to work with the MCC on possible language that could be added to the common examples of special facilities listed in Section 5.03 to include reporting of outage information as an available option to customers.

X. Minimum System Study.

481. In preparing its CCOSS, OTP relied on a minimum system study from 2005.[599] The minimum system study is used in categorizing certain distribution costs as customer and demand related. OES recommended that the Company be required to use an updated minimum system study in its future CCOSS filings using data less than three years old.[600] OTP accepted this recommendation.[601]

Y. Miscellaneous Tariff Changes.

482. OTP proposed revisions to its General Rules and Regulations incorporating current references to Minnesota Statutes and Rules, adding clarifying language, updating contact information, and renumbering and reorganizing portions of its tariff, which the OES summarized in OES Attachment SLP-7.[602] The OES found that OTP had fully supported its proposed changes and recommended approval.[603]

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[595] Ex. 57, Schedin Direct at 22-23.
[596] Ex. 42, Prazak Rebuttal at 20.
[597] *Id*.
[598] Tr. 2:22-23.
[599] Ex. 36, Beithon Rebuttal at 40.
[600] Ex. 77, Ouanes Direct at 9.
[601] Ex. 36, Beithon Rebuttal at 40; Ex. 80, Ouanes Surrebuttal at 5.
[602] Ex. 81, Peirce Direct, Attachment SLP-7.
[603] *Id*. at 20.

Z. MISO Attachment O Revenues.

483. The Company included MISO transmission revenues received from the users of its transmission system as an offset to the test year revenue requirement. The Company initially included MISO Attachment O transmission revenues based on projects in effect during the 2009 actual year.

484. In response to OES Information Request No. 137, the Company agreed that it was appropriate to include projects being put into service in 2010. Inclusion of the 2010 projects results in an increase to MISO Attachment O Revenues of $35,247.[604]

485. The OES recommended that the Company's 2010 MISO Attachment O revenues be increased by $35,247 to reflect the revenues from this additional transmission plant for 2010.[605] The Company agreed to this adjustment.[606]

AA. Net Taxes.

486. OES expressed concern over the Company's calculation of net taxes and requested that OTP recalculate its allocation of income taxes.[607] OTP believed that it had correctly calculated the net taxes.[608] The OES agreed that OTP had intended to calculate the taxes correctly, but had made an error in the process.[609] Based on further discussion with OES, the Company agreed that an error had been made that should be corrected in OTP's next rate case.

487. OES found that the CCOSS provided satisfactory information to be used in this proceeding; the need for a future change related to the net taxes was a refinement.[610]

BB. Non Asset-Based Margins.

488. The Company operates a non-regulated business that participates in the energy market for profit. This business is conducted by the same employees who buy and sell energy on the wholesale market. These wholesale margins are referred to as non asset-based margins.[611] As a non-regulated business, an appropriate amount of its cost must be removed from the retail revenue requirement to ensure that retail customers do not subsidize this activity.[612]

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[604] Ex. 36, Beithon Rebuttal at 60.
[605] Ex. 98, Campbell Direct at 34.
[606] Ex. 36, Beithon Rebuttal at 60.
[607] Ex. 77, Ouanes Direct at 13-15.
[608] Ex. 36, Beithon Rebuttal at 38-39.
[609] Ex. 79, Ouanes Rebuttal at 4.
[610] Ex. 80, Ouanes Surrebuttal at 4.
[611] Ex. 36, Beithon Rebuttal at 58.
[612] *Id*. at 59.

489. The Company originally proposed use of an incremental cost of providing service, as opposed to an embedded cost, to allocate $370,238 of 2009 test year administrative and general expenses to this below-the-line business activity.[613]

490. OES and the MCC both recommended using the fully allocated cost of providing service instead of incremental cost.[614] If fully allocated costs were used, $503,000 of expenses would be allocated below-the-line, reducing administrative and general expenses by $132,952 in the 2009 test year.[615]

491. The Company accepted the use of the embedded cost methodology for the purposes of this rate case, but reserved the right to change the methodology back to using incremental cost in the event that circumstances changed in the future.[616]

492. OTP and the OES also agreed that the cost of workstations should be included in the embedded cost study. Including workstations reduces rate base by $4,800, of which $2,400 is attributable for the Minnesota jurisdiction. OTP agreed to make this adjustment,[617] which OES accepted.[618]

CC. Rate Base Capacitor Banks.

493. OTP proposed including the Gwinner Capacitor Bank project in rate base. The project involved the addition of two new 115 kV, 6 MVAR capacitor banks at the Gwinner, North Dakota substation.[619] The OES initially objected to the inclusion of this project as a known and measureable change, because only 3 percent of the project cost had been completed at the time the petition for a rate increase was filed.[620] OTP updated the status of the project in rebuttal testimony.[621] The OES then concurred that the project should be included as plant-in-service with a Minnesota jurisdictional amount of $422,861.[622]

DD. Spousal Travel.

494. In response to the OAG's Information Request MN-OAG-263, the Company identified the inclusion in the test year of travel expenses for spousal airfare, meals, and lodging expenses in the amount of $1,328 for the total company, of which

[613] Ex. 34, Beithon Direct at 25-26.
[614] Ex. 98, Campbell Direct at 18-26; Ex. 57, Schedin Direct at 21.
[615] Ex. 98, Campbell Direct at 26.
[616] Ex. 36, Beithon Rebuttal at 60.
[617] Ex. 36, Beithon Rebuttal at 60.
[618] Ex. 106, Campbell Surrebuttal at 3; *see also* Ex. 112, Lusti Revised Surrebuttal at 21, DVL-RS-4W, column (d).
[619] Ex. 24, Sem Direct at 22.
[620] Ex. 96, La Plante Direct at 4-5.
[621] Ex. 25, Sem Rebuttal at 1-3.
[622] Ex. 97, La Plante Surrebuttal at 1-3.

$664 was for the Minnesota jurisdiction.[623] At the request of the OAG, the Company agreed to remove these travel expenses for spousal travel from the test year.[624]

EE. TailWinds Program.

495. During the course of responding to IR EE-140, OTP identified an error in the allocation of costs to the TailWinds program.[625] The impact on the Minnesota jurisdiction is a reduction of $180,344.[626]

FF. Updated Salary Information.

496. In response to OES Information Request No. 177, OTP agreed to reduce its 2010 adjustment for wage increases to reflect the 2.4 percent actual increase for executives instead of the 5 percent increase originally proposed by OTP. The impact of this adjustment in the revenue requirement is $13,767, as shown on (PJB-2), Schedule 5.[627]

Based on these Findings of Fact, the Administrative Law Judge makes the following:

CONCLUSIONS

1. The Minnesota Public Utilities Commission and the Administrative Law Judge have jurisdiction over this proceeding pursuant to Minn. Stat. Ch. 216B and Section 14.50.

2. Every rate made, demanded, or received by any public utility shall be just and reasonable. Rates shall not be unreasonably preferential, unreasonably prejudicial or discriminatory, but shall be sufficient, equitable, and consistent in application to a class of consumers. To the maximum reasonable extent, the Commission shall set rates to encourage energy conservation and renewable energy use and to further the goals of sections 216B.164, 216B.241, and 216C.05. Any doubt as to reasonableness should be resolved in favor of the consumer.

3. The burden of proof to show that a rate change is just and reasonable shall be upon the public utility seeking the change.

4. If an applicant and all intervening parties agree to a stipulated settlement of the case or parts of the case, the settlement must be submitted to the Commission. The Commissions shall accept or reject the settlement in its entirety. The Commission may accept the settlement on finding that to do so is in the public interest and is supported by substantial evidence.

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[623] Ex. 62, Smith Direct at Schedule RLS-30.
[624] Ex. 36, Beithon Rebuttal at 63.
[625] Ex. 38, Beithon Surrebuttal at 13.
[626] Ex. 36, Beithon Rebuttal at 42.
[627] *Id*. at 46.

5. In the event the Commission rejects the agreements of the parties, this matter may be extended by 60 days for conclusion of the contested case proceedings under the terms of Minn. Stat. § 216B.16, subds. 1a and 2.

6. The record supports the resolution of the settled, resolved, and uncontested matters identified above. These matters have been resolved in the public interest and are supported by substantial evidence.

7. Rates set in accordance with the terms of this Report would be just and reasonable.

Based upon these Conclusions, the Administrative Law Judge makes the following:

RECOMMENDATION

The Administrative Law Judge recommends that the Commission issue an Order providing that:

1. Otter Tail Power is entitled to increase gross annual revenues in accordance with the terms of this Report.

2. Within ten days of the service date of this Report, Otter Tail Power shall file with the Commission for its review and approval, and serve on all parties in this proceeding, revised schedules of rates and charges reflecting the revenue requirements for 2009 and the rate design decisions based on the recommendations made herein.

3. Otter Tail Power shall make further compliance filings regarding rates and charges, rate design decisions, and tariff language as ordered by the Commission.

Dated: February 14, 2011

s/Kathleen D. Sheehy
KATHLEEN D. SHEEHY
Administrative Law Judge

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NOTICE

Notice is hereby given that, pursuant to Minn. Stat. § 14.61, and the Rules of Practice of the Public Utilities Commission and the Office of Administrative Hearings, any party adversely affected by this Report may file exceptions to it within 15 days of the mailing date hereof. Exceptions should be filed with the Executive Secretary, Minnesota Public Utilities Commission, 350 Metro Square, 121 Seventh Place East, St.

Paul, MN 55101. Exceptions must be specific and stated and numbered separately and should include Proposed Findings of Fact, Conclusions and an Order. Exceptions should be e-filed with the Commission and served upon all parties. Oral argument before a majority of the Commission will be permitted to all parties adversely affected by the Administrative Law Judge's recommendation who request such argument. Such request must accompany the filed exceptions or reply. An original and 15 copies of each document should be filed with the Commission.

The Minnesota Public Utilities Commission will make the final determination of the matter after the expiration of the period for filing exceptions or after oral argument, if held. Further notice is hereby given that the Commission may, at its own discretion, accept or reject the Administrative Law Judge's recommendation and that the recommendation has no legal effect unless expressly adopted by the Commission as its final order.

Under Minn. Stat. § 216B.16, subd. 1a, if the Commission rejects or modifies the settlement agreements reached herein, this matter may be extended by 60 days for conclusion of the proceeding.

Under Minn. Stat. § 14.63, subd. 1, the Commission is required to serve its final decision upon each party and the Administrative Law Judge by first class mail or as otherwise provided by law.